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Role of coal in Indian energy scenario

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Conversion

To covert one metric tonne of the following to one tonne of oil equivalent (toe)

Products	Multiplier
LPG	1 130
Naphtha	1.075
Aviation gasoline	1.070
Motor gasoline	1.070
Jet fuel	1 065
Kerosene	1 045
Gas/diesel	1.035
Residual fuel oils	0 985
Others	0 960

Abbreviations

AFBC	-	Atmospheric Fluidised bed combustion
ARC	-	Alberta Research Council
ATF	-	Aviation turbine fuel
BAU	-	Business-as-usual
BCCL	-	Bharat Coking Coal Limited
BCM	-	billion cubic meter
BkWh	-	billion kilowatt hour
BP	-	British Petroleum
Bt	-	billion tonne
Cal	-	calorie
CBM	-	Coal bed methane
CCL	-	Central Coalfield Limited
CCT	-	Clean coal technology
CEA	-	Central Electricity Authority
CERI	-	Canadian Energy Research Institute
CIF	-	Cost, insurance and freight
CIL	-	Coal India Limited
CIS	-	Common wealth of Independent States
CME	-	Centre for Mining Environment
CMIE	-	Centre for Monitoring Indian Economy
CMPDI	-	Central Mine Planning and Design Institute
cu.m	-	cubic meter
DSM	-	Demand side management
DVC	-	Damodar Valley Corporation
ECE	-	Economic Commission for Europe
ECL	-	Eastern Coalfields Limited
ELGEM	-	Electricity Generation Expansion Model
ESP	-	Electrostatic precipitator
EU-12	-	European Union-12
FO	-	Fuel oil
Gcal	-	Gross calorie
GCV	-	Gross calorific value
GDP	-	Gross domestic product
GMDC	-	Gujarat Mineral Development Corporation
GOI	-	Government of India
Gr	-	Grade
GSI	-	Geological Survey of India
GW	-	Giga watt
Gwh	-	Giga watt hour
ha	-	hectare
HSD	-	High speed diesel
IEA	-	International Energy Association

IGCC	-	Integrated gas combine cycle
IISCO	-	Indian Iron & Steel Company
IR	-	Indian Railway
kCal	-	kilo calories
kCal/kg	-	kilo calories per kilogram
kW	-	kilowatt
kWh	-	kilowatt hour
LPG	-	Liquid petroleum gas
M sq. km	-	million square kilometer
m	-	meter
m/s	-	meter per second
MAS.	-	Madras
MCL	-	Mahanadi Coalfields Limited
MCM	-	Million cubic meter
MGR	-	Merry-go-round
MMBTU	-	Million British thermal unit
MMHP	-	Mini micro hydel power
MMSCMD	-	Million standard cubic meter per day
MNES	-	Ministry of Non-conventional Energy Sources
MOC	-	Ministry of Coal
MOI	-	Ministry of Industry
MP	-	Madhya Pradesh
MS	-	Motor spirit
Mt	-	million tonne
Mtoe	-	million tonne oil equivalent
MW	-	mega watt
NCL	-	Northern Coalfields Limited
NEC	-	North-Eastern Coalfields
NG	-	Natural gas
NLC	-	Neyveli Lignite Corporation
NTPC	-	National Thermal Power Corporation
OC	-	Open cast
OECD	-	Organisation for Economic Cooperation and Development
PDP.	-	Paradeep
PDP_MAS	-	Pradeep-Madras
PDP_VZA	-	Pradeep-Vizag
PFBC	-	Pressurised Fuel Bed Combustion
PLF	-	Plant load factor
PPPs	-	Private power producers
RET	-	Renewable energy technology
RITES	-	Rail India Technical and Economic Services
ROR	-	Rate of return
Rs	-	Rupees
SCCL	-	Singerani Coal Company Limited
SEB	-	State electricity board

SECL	-	South-Eastern Coalfield Limited
SHP	-	Small Hydro Power
SKO	-	Superior kerosene oil
T&D	-	Transmission and distribution
tce	-	tonnes coal equivalent
TERI	-	Tata Energy Research Institute
TISCO	-	Tata Iron & Steel Company
TSP	-	Total suspended particulate
TWh	-	Terra watt hour
UAE	-	United Arab Emirates
UG	-	underground
UNEP	-	United Nations Environmental Program
VZA	-	Vizagapatnam
WC	-	washed coal
WCL	-	Western Coalfield Limited
WGC	-	Working Group on Coal
Whr	-	Watt hours

PART I

Executive Summary

Role of coal in Indian energy scenario

Commercial energy consumption

For any developing country, the key issues are economic growth, access to adequate commercial energy supplies and the finances needed to achieve this. In the developing world, the first sign of improving standard of living is the increasing supply of energy. In India, the per-capita consumption of energy is only 0.24 toe as against the world average of 1 toe and much higher levels in developed countries. The per-capita consumption of energy is likely to rise in the future and though it may not come anywhere closer to that of developed countries, it will definitely see a steep increase in the next 10 -15 year span resulting in increased demand of energy. At the projected population of 1196 million and projected consumption of energy resources at 468 Mtoe in the year 2011-12, the per-capita consumption is likely to reach a figure of 0.4 toe.

The importance of the energy sector as an input to development is well known The growth in consumption of energy is a function of the growth of the economy. Currently, the demand for global energy is increasing at an average rate of 2 % per year. At this rate, the energy consumption will double every 35 years.

In India, commercial sources of energy account for more than 60% of the total energy supplies, while non-commercial sources make up the balance. Given the large resources of coal, it dominates the commercial energy supply profile. Energy consumption in India, however, is constrained by supply shortages *In view of the shortages and restrictions, the past trend of consumption of commercial energy does not represent the growth of demand for such energy but merely reflects the growth of its actual availability.*

Non-commercial energy (biomass) is estimated to contribute less than 40% of the total energy consumed in the country, due primarily to its large rural base. However, with increased urbanization, depleting supply of fuel wood and availability of commercial energy to rural environs, the share of non-commercial energy will witness a decline in the coming two decades.

The indigenous production of commercial energy in India has increased from a level of 53 Mtoe in 1972-73 to about 183 Mtoe in 1994-95, registering an average annual growth rate of 5.8%. This rate of growth is likely to continue if investment constraints were removed. The fuelwise, sectorwise commercial energy consumption in 1994-95 is given in Table i. Industrial sector consumes 50% of the total energy followed by the transport sector. Industrial sector is the largest consumer of coal & electricity and for petroleum products, it is the transport sector.

Table i Sectoral Commercial energy consumption for 1994-95 (Mtoe)

Consumption	Coal	Natural gas	Petroleum products	Power	Total energy
Agriculture	-	0.1	0 9	6.7	7 7
Industry	53.9	1.5	10 0	8.5	73 9
Transport	0.3	-	32 6	0 5	33.4
Residential	-	0.2	11 1	4 0	15 4
Other uses	-	-	2.1	2 5	4 6
Non-energy uses	-	6 0	7 6	0.0	13 6
TOTAL	54.2	7 8	64 3	22.2	148 6*

Source: TEDDY 1996
* availability, net of conversion losses / stock adjustments etc.

Sectoral consumption of coal

Power sector is the largest consumer of coal with a share of 70% in the total consumption of coal. This is followed by the industrial sector with a share of about 29%. In the industrial sector, the major consumers of coal are steel (13%), cement (4%) and brick kilns (4%). The consumption of coal in the domestic sector is insignificant.

Table ii Sectoral consumption trend - coal (Mt)

Sector	1960-61	1970-71	1980-81	1990-91	1994-95	%
1. Steel & Coke Ovens	9 1	13 5	22.4	27.6	33 4	13
2. Power(U)	9.1	13 2	36.7	116.7	166 7	64
3. Power (C)	#	#	#	12.5	14 5	6
4. Cement	2 3	3 5	4.8	9.7	11 2	4
5. Fertilizer	#	#	2 3	3.9	4 3	2
6. Railways	15.5	15 6	11.9	5 2	0 7	-
7. Soft Coke	2.6	4.1	1.3	1.3	0 5	-
8. Others	14.6	21 8	30.3	30.7	28.8	11
TOTAL	53.2	71.7	109 7	207 6	260 1	100

Source: Ministry of coal
accounted for in 'Others' category

Fuel substitution

Power sector

Indigenous coal can be substituted by other fuels including imported coal in power sector, subject to techno-economic feasibility. In cement industry, the imported coal can replace to a limited extent the indigenous coal in the southern belt, especially with low availability of appropriate quality indigenous coal and the waiver of import duty for coal import against export of cement . The brick industry, though is trying to use other fuels in conjunction with coal, such as fuel wood, will continue to be largely dependent on coal as the main source. The possibility of fuel substitution is ruled out in the existing power plants in northern and central India because of the increased cost of inland transportation of imported fuel and in eastern

India because of the proximity to the coalfields. However, the plants in south India, both existing and new, clearly have wider options for choosing the fuel. While the existing plants in southern India can use imported coal as a sweetener to the maximum extent of about 30%, the new plants can be designed to use imported coal. However, large volume imports of coal are dependent on the port infrastructure, which will need huge capital investment and construction time. The option of using oil, natural gas (NG) in both piped and liquified form (LNG) is also available to these power plants.

The steel industry is already using imported coal to a large extent and will continue to do so because of the shortage of good quality coking coal in India. Any substitution of coal in steel industry by other fuels is unlikely but natural gas can be gainfully utilized in the production of sponge iron.

Pattern of capacity build-up and power generation from different fuels

Capacity build-up

The generating capacity of utilities comprises a mix of hydro, coal / oil / gas based thermal and nuclear plants. The installed capacity, which was about 1,700 MW in 1950-51 has grown to 81,000 MW by 1994-95. The annual rate of growth is about 9.5% during this period. Up to mid 1960s, the thrust was more on developing hydel projects, but, since 1970s, the thermal capacity has shown remarkable increase and its share is 71% in 1994-95. The share of hydro power rose to 43% in 1970-71, but has been steadily declining and is about 26% in 1994-95. The share of hydro-capacity has been declining due to various reasons including adverse environmental impact and large scale displacement of population The share of nuclear power is almost stationery at about 3% Table iii gives the installed capacity and also the share in different periods. The share of coal based thermal in total thermal generation capacity is 91% in 1994-95 The annual rate of growth of installed capacity for various periods is given in Table iv.

Table iii Installed capacity (000 MW)

Year	Utilities						Total
	Hydro	%	Thermal	%	Nuclear	%	
1950-51	0.6	35	1 1	65	-	0.0	1.7
1960-61	1.9	41	2 7	59	-	0.0	4.6
1970-71	6.4	43	7.9	54	0.4	3	14.7
1980-81	11.8	39	17.6	58	0 9	3	30.2
1990-91	18.8	28	45.8	69	1.5	3	66 1
1994-95	20.8	26	58 1	71	2.2	3	81 1

Source: Economic Survey 1995-96

Table iv Annual rate of growth of installed capacity (%)

Period	Thermal	Hydro	Total
1950/51-1960/61	9.1	13.1	10.5
1960/61-1970/71	11 8	12.8	12.2
1970/71-1980/81	8.2	6.3	7.4
1980/81-1990/91	9.7	4 6	7.1
1950/51-1994/95	9 7	9 1	9.5

Source: CMIE, 1991

Power generation

The gross power generation from utilities has increased rapidly from 5 1 Billion kWh in 1950 to 351 BkWh in 1994-95, registering an average growth rate of about 10% per annum The details of gross generation and growth rates for different periods are given in Table v and Table vi.

Table v Gross electricity generation (BkWh)

	Hydro	%	Thermal #	%	Nuclear	%	Total generation
1950-51	2.5	49	2.6	51		-	5 10
1960-61	7.8	46	9.1	54		-	16 90
1970-71	25 2	45	28 2	51	2 4	4	55 80
1980-81	46 5	42	61 3	55	3 0	3	110 80
1990-91	71 7	27	186 5	71	6 1	2	264 30
1994-95	82 5	23	262 9	75	5 6	2	351 00

Source. Economic Survey 1995-96 # coal, diesel & gas

Table vi Annual rate of growth of gross generation (%)

Period	Thermal	Hydro	Total
1950/51-1960/61	13 4	12 0	12 7
1960/61-1970/71	12 9	12 4	12 7
1970/71-1980/81	7 7	6 3	7 2
1980/81-1990/91	11 6	4 4	9 1
1950/51-1994/95	11 2	8 0	10 1

Source: CMIE, 1991

Energy demand projections

There are several approaches to energy demand analysis. Many demand estimates are based on an extrapolation of the past trends. TERI had recently carried out an analysis of the energy demand projections till 2011-12 under a study sponsored by United Nations Environmental Program (UNEP) titled "Environmental considerations and options in managing India's long-term energy strategy" (November 1995). In this analysis, the growth prospects of other economic sectors like transport, agriculture, has largely been estimated on the basis of past trends. However, in the case of industry, use had been made of industry's own planned growth and government's projections wherever possible.

Among the various scenarios for energy demand developed in the study, the results of energy conservation scenario are discussed here. This scenario considers energy conservation measures together with improvement in agricultural pump sets, reduction in transmission and distribution (T&D) losses etc. Since conservation measures generally take time to be implemented, these options have been considered from the Ninth Plan.

Under the energy conservation scenario, the savings in coal, petroleum products and natural gas has been worked out for the different terminal years of future plans and the resultant fuel-wise energy demand is given in Table vii.

Table vii Fuel-wise energy demand under energy conservation scenario

Fuel	Unit	2001	2006	2011
Coal	Mt	352.6	438.0	554 0
Natural gas	BCM	36 6	43.8	58.5
Petro products	Mt	75.5	99.5	127.0
Primary electricity	TWh	166 2	213 0	235 5

Source: UNEP study (TERI)

Coal demand as assessed by Working Group on coal

The Working Group for the 9th Plan constituted by the Ministry of Coal in November 1995 has assessed the coal demand for 9th Plan and beyond. As per this report, the coal demand is estimated at 440 Mt in 2001-02 (as against 394 Mt assessed by the Planning Commission in the 8th Plan document) and 557 Mt in 2006-07 and 711 Mt in 2011-12. This assessment of coal demand is probably based on business-as-usual scenario and therefore it is higher than TERI's projection under energy conservation scenario. The sector-wise coal demand as assessed by the Working Group is given in Table viii.

Table viii Sector-wise coal demand - Mt

Sector	1996-97	2001-02	2006-07	2011-12
Iron & steel	40 5	51 6	64.0	78.0
Power (utilities)	210 0	291 2	351.0	435.0
Cement	15 3	19 9	30.0	45 0
Others	59 2	77 0	112.0	153.0
Total	325 0	439 7	557 0	711 0

Source: Ministry of Coal (Working Group on coal and lignite)

It is evident from the sectoral consumption trend and demand projections that coal for power generation is and would remain as the single major fuel source on the energy scene in short and medium-term.

Future power generation projections for India

A linear programming model called ELGEM (Electricity Generation Expansion Model) jointly developed by the Canadian Energy Research Institute (CERI) and the Alberta Research Council (ARC), has been used by TERI to project the demand for different fuels for generation of electricity. The Base Case representing a Business as Usual development strategy for the power sector was developed where, other than limitations on expansion of hydro-electric generation capacity up to 80 GW; natural gas utilization restricted to a maximum of 14.7 billion cubic meters (BCM) per annum; and new nuclear capacity restricted to an additional 27 GW by 2011; was an unconstrained, least cost development scenario which meets all projected electricity demand.

The development scenario in the Base Case was found to be clearly unrealistic for India. In particular, the financial investment required to underwrite the implied capacity expansion would necessitate an unprecedented diversion of national income to the power sector, assuming that the major portion of financial investment for power sector development were to be provided by the government.

Reference case

For purposes of comparison with alternative development scenarios, it was decided to generate a Reference Case scenario based on a realistic set of initial constraints for power sector development. The structure of this scenario is the same as the Base Case, except:

- a financial constraint is imposed limiting capital investment in the power sector to historical levels of 3 2 percent of GDP forecast for India,
- a coal constraint is imposed limiting coal available for electric power generation to 406 Mt in 2011. This constraint is imposed to capture both the physical capabilities of the mining and transportation network to provide coal volumes, and the declining quality of available coal; and
- renewable sources of electricity supply are assumed as part of the available generation mix.

The results of the Reference Case scenario are tabulated below. Investment reaches Rs 264,560 crores in 2011, compared to Rs 315,041 crores under the Base Case, a reduction of 16 percent. Total installed capacity increases 3.25 times from 1991 levels to nearly 225 GW in 2011. Coal-fired generation expansion is constrained significantly relative to the Base Case, reaching 125 GW in 2011 compared to 214 GW in the Base Case.

The projected generating capacity at the end of the 9th, 10th and 11th plan is given in the Table ix and the consumption is given in Table x.

Table ix Projected Installed Capacity (MW)

Energy resource	2001	2006	2011
Coal	67327	91502	125421
Nuclear	6131	12051	18004
Natural gas	20483	21010	22027
Hydro	35261	46860	59415
Other	3200	4800	6400
Total	132402	176223	231267

Sources: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council, and Tata Energy Research Institute

Table x Projected fuel consumption

Fuel	Unit	2001	2006	2011
Coal	Mt	246	320	406
Natural gas	BCM	12.6	13.7	14.7
Nuclear	'000 kg U	3122	6203	9299

Source: ELITE, December 1994

The following points are important·

- There is a shortfall of 20% of total capacity required in 2011. This is the major impact arising out of constraining coal and financial resources available.
- The share of hydro electric capacity remains at 26% in 2011 which is the same as in 1994-95.
- Due to fuel constraints and limited resource availability, there is a substantial reduction in coal-based generation capacity, and an associated reduction in emissions.

Decentralized generation

As mentioned, this scenario introduces a series of renewable generation options to the array of alternative generation sources available to the model. As shown in Table xi, 6400 MW of renewable capacity comes on stream by 2011.

Table xi Decentralized generation by region in 2011(MW)

	North-east	North	East	West	South	Total
Biogasification	600	400	0	600	400	2000
Micro Hydroelectric	240	480	240	0	1440	2400
Wind	0	0	0	600	1400	2000
Total	840	880	240	1200	3240	6400

Source: ELITE, December 1994

Renewable energy technology (RET) potential

The potential of biomass based power, small hydro, and wind related power together is projected at 47,000 MW. Total installed capacity is 1,000 MW. The potential of some of the RETs and the capacity expected to be installed by 2011 are given in Table xii. Generation through other technologies like ocean thermal, sea wave power and tidal power are not expected to add anything significant to the total generation by 2011.

Table xii Renewable energy potential and projection (MW)

Source/technology	Units	Potential/ availability	Potential exploited upto March 1995	Expected to be in position by 2011
Biomass based power	MW	17,000	100	2,000
Small hydro	MW	10,000	400	2,400
Wind energy	MW	20,000	500	2,000
Total		47,000	1000	6,400

Source: MNES annual report and documents referred in text

Wind power

Wind farms appear to be one of the most feasible and cost effective mode for supplementing the conventional means of power generation on a large scale. The technical viability of the wind farms have been established in India. 500 MW capacity wind farms are already in operation and another 1500 MW are in various stages of planning in the coastal states of Tamil Nadu, Gujarat, Andhra Pradesh, Kerala, Karnataka and Madhya Pradesh in central India. Estimates by the Ministry of Non-conventional energy Sources (MNES) place the realizable wind energy potential in India at 20,000 MW. There is, however, a significant difference between the ultimate and the realizable potential of wind energy and this is largely due to the highly intermittent nature of wind energy source and the characteristics of the grid.

Small hydro power

In India, the small, mini and micro hydel systems together are treated as small hydro power (SHP) systems covering a wide range of sizes and capacities. The classification adopted is as follows:

- Micro-hydro. Less than 100 kW
- Mini-hydro: 101-2,000 kW (unit size up to 1 MW)
- Small-hydro: 2,001-15,000 kW (unit size up to 5 MW)

Presently, the responsibility of promoting MMHP up to 3 MW lies with MNES while the CEA looks after hydro power from 3-15 MW. MNES estimates that the total small-hydro potential for India up to 15 MW capacity is likely to be over 10,000 MW. About half of this is expected to be in mini and micro hydro categories in the hilly areas and in the north-eastern region.

Biomass energy

An overwhelming proportion of the rural domestic energy is supplied by the biomass fuels. In the rural areas, biomass fuel is mostly collected at a zero private cost, and no formal distribution systems exist like in the case of commercial fuels. Hence, it is difficult to correctly estimate, either at the micro or macro level, how much biomass is supplied from what type of land. This process is rendered even more difficult in the absence of reliable biomass assessment techniques for large-scale enumeration

Demand side management, cogeneration and clean coal technologies

The shortfall of 20% (60000 MW) in capacity between reference case and base case can be made up to a large extent through measures like DSM, co-generation and clean coal technologies. This has been taken into account in the model under optimistic scenario projection The result are as follows

Table xiii Projected DSM capacity (MW)

	2001	2006	2011
Demand-side management	4893	1500	11129
Cogeneration	1900	7076	13294
Clean coal technologies	0	6272	23777

DSM

- The Inter-Ministerial Working Group on energy conservation has estimated that there is a potential of 20%, 20% and 15% energy savings in coal-based, oil-based and electrical equipment respectively, in the existing system. This will be achieved by the installation of heat recovery systems, replacement of inefficient boilers, computerization of process control operations, adoption of cogeneration systems and use of energy efficient equipment and lighting in domestic and commercial sectors

- There has been a lot of efforts to spread awareness to save energy via the demand side management. The success of DSM will depend on an active involvement of the producer and the consumer, which, in India is lacking because the distribution, billing and realization of the dues has not been ideal resulting in total disinterest of the consumer. Some electricity boards have started taking steps in the right direction and Orissa has shown the path. In Orissa power restructuring scheme, DSM has a big role to play. However, the experts in this area do not see miracle happening in the next ten to fifteen years.

Cogen

Significant cogeneration potential has been identified in the Indian industrial sector. A study carried out by TERI in 1993, based on a detailed survey of 300 industrial units, estimated a total cogeneration potential of about 7,500 MW, of which the sugar industry alone was estimated to account for over 65% of the total identified cogen potential. Substantial potential also exists in the textile and paper industry.

CCT

Clean coal technologies (CCT) offer the potential for significant reduction in environmental emissions and improved efficiencies when used for power generation. These technologies include use of integrated gasification combined cycle (IGCC), pressurized fluidized bed combustion (PFBC) and atmospheric fludised bed combustion (AFBC) to improve the efficiency of combustion. These also includes use of washed non-coking coal Due to the increased efficiency same amount of power can be generated by reduced amount of coal used.

Status of commercial energy resources

Coal

Coal reserves

India is relatively well endowed with both exhaustible and renewable energy resources. Coal is the major exhaustible energy resource in the country and has a life expectancy of over 200 years. The total coal reserves have been assessed at about 202 Billion tonnes(Bt) of which 70 Bt (about 35%) are proved reserves.

The salient features of coal reserves are as follows:

- About 63% of the total coal reserves occur within 300 m depth and 26% occurs in the depth range from 300-600 m depth. Only about 10% reserves occur beyond 600 m depth in deep coal basins like Jharia and Raniganj coalfields
- Coking coal reserves are only 15% of the total coal reserves, confined to only 10 out of the 62 coalfields in Bihar, West Bengal and Madhya Pradesh
- Reserves of non-coking coals amount to about 85% of the total reserves of which only 12% are of superior grade and occurring mostly in Raniganj.
- Therefore, it can be concluded that bulk of the coal reserves (73%) are inferior grade non-coking coals occurring in thick inter-banded seams and located in coalfields like Singrauli, Talcher, North Karanpura, Rajmahal, Ib Valley and Korba, etc.

The power grade coal comprising grades E, F & G of non-coking coal is estimated to be 40 9 Bt. Large proportion of this reserve is in shallow deposits and thus amenable to open cast mining.

Coal production

Coal industry was nationalized in two stages viz. coking coal mines were taken over in October 1971 and all other coal mines in January 1973. This was done, apart from other considerations, with a view to ensure that the production of coal which is the primary source of energy should be properly planned to meet the increasing requirements in the industrial development of the country. It was expected that nationalization of the coal industry would also ensure fair and equitable distribution of coal to meet the essential needs of users, both in the core and non-core sectors.

To ensure sustained and planned development of all facets of the coal industry, massive investment to the tune of about Rs. 18,000 crores has been made since nationalization in opening up of new mines, re-organization of existing mines and development of associated infrastructure. Coal production has registered an annual growth

rate of about 4.3% since nationalization, increasing from a level of 73 Mt in 1970-71 to 270 Mt in 1995-96. In the post-nationalization period, major thrust was given towards development of new outlying coalfields like Rajmahal, North Karanpura, Singrauli, Korba, Ib valley and Talcher. These coalfields contributed 43% of the total coal production in 1994-95. Consequent upon development of new coalfields in outlying areas, a large number of pit-head super thermal power stations have come up. This has helped in reducing the load on railways as most of these pit-head power stations transport their coal by captive modes such as merry-go-round (MGR) system. The production, dispatch and closing stock from 1970-71 to 1995-96 are given in Table xiv.

Table xiv Production dispatches and stocks of coal (Mt)

Year	Production	Dispatches	Closing stocks
1961-62	55.2	50.8	3.
1970-71	72.9	62.2	9.
1980-81	113 91	105.76	18 2
1990-91	211 73	201.07	42 5
1994-95	253 73	248.43	46.4
1995-96	270 12	267 00	37 5

Source: Ministry of Coal

The large increases in production could be achieved through enhanced investment in the coal industry by the government, deliberate shift in technology, increased emoluments and welfare amenities for coal workers and other measures. The Government adopted a deliberate policy to increase production through opencast mines to meet the increasing demand of coal for the utilities The opencast mines which contributed only about 28% of the total production at the time of nationalization (1973) increased their share to about 72% in 1995-96. The major factors in favour of opencast mines are shorter gestation period, high recovery and safety, and lower cost of production. However bulk of coal produced from opencast mines is inferior grade coal. As a result of this policy, the production of inferior grades of both coking and non-coking coal have been increasing in the last two decades and this trend is continuing. The details of technology-wise and type-wise production are given in Table xv and Table xvi.

Table xv Technology-wise coal production (Mt)

Year	Underground		Opencast		Total
	Mt	%	Mt	%	Mt
1970-71	58 2	80	14 7	20	72 9
1980-81	73 3	64	40 7	36	114 0
1994-95	76 1	30	177 7	70	253 8
1995-96	74 0	28	196 1	73	270 1

Source: Ministry of Coal

In 1970-71, 24% of total coal produced was coking and 76% was non-coking. The production of the non-coking coal over the years have increased sharply, mainly due to the increasing demand of power coal and now it stands at 84%. The percentage of coking coal production in total production has declined to 16% during the same period. Moreover, not all coking coal is used for metallurgical purposes and 45% of coking coal production is again consumed by other industrial sectors including power.

Table xvi Type-wise coal production (Mt)

Year	Coking		Non-coking		Total
	Mt	%	Mt	%	Mt
1970-71	17 8	24	55.1	76	72 9
1980-81	26 8	24	87 2	76	114.0
1994-95	41.97	17	211.76	84	253.73
1995-96	42 92	16	227 20	84	270.12

Source: Ministry of Coal

In the non-coking coal production, the share of superior quality coal (Grades A, B C & D) in 1970-71 was about 80% which has declined in 1995-96 to about 50% The balance 50% was inferior grade non-coking coal (Grade E, F & G). This declining trend in the production of superior grades is likely to continue in the future.

Coalfields like Jharia, West Bokaro, East Bokaro and Ramgarh produce largely coking coals. Raniganj, South Karanpura, Patherkhera, Pench Kanhan, Korba, Central India and North East Coalfields produce all the superior quality non-coking coal. Bulk of the inferior grade non-coking coal production comes from Rajmahal, North Karanpura, Singrauli, Wardha, Korba, Ib valley, Talcher and Singareni coalfields. Out of these Wardha, Rajmahal, Singrauli and Singareni are almost fully committed to pit-head power stations. The coal demand of distant power houses are largely met from North Karanpura, Ib valley, Talcher and Korba coalfields The coalfieldwise coal production programme is given in Table xvii

Coal production programme for meeting the demand

Table xvii Coalfield-wise coal production and projections for future (Mt)

Coalfield	1996-97	2001-02	2006-07	2011-12
Raniganj	18.40	20 92	26 00	27 00
Mugma Salanpur	4 82	3.76	3 00	2.00
Rajmahal	9.52	13.02	16 00	20 00
Jharia	28.24	34 40	36 00	36.00
Giridih	0.45	0.30	0 50	0.50
West Bokaro	3.73	5.45	16.50	22 00
East Bokaro	10.38	8.12	13.00	15 00
Ramgarh	2.50	2.60	3 00	3 00
South Karanpura	5.29	5.05	11 00	12 50
North Karanpura	12 85	19 74	26 00	47.00
Singrauli	37 00	49.00	58 00	67 00
Wardha Valley	17.71	19.10	22 50	23 60
Kamptee	2.88	2 90	3 20	3 20
Umrer	2.59	2 40	0 80	0 00
Patherkhera	2 57	2 73	2 10	1 50
Pench-Kanhan	3.75	3.57	4 40	4 70
Central India	20 10	24.20	24 00	24 00
Korba	32.40	41.22	63.00	67 00
Mand Raigarh	0.00	0.52	2 00	4 00
Ib valley	12.55	13 80	43 00	60 00
Talcher	23 47	29.20	51 00	80.00
North-East	0.80	1 00	2 00	2 00
COAL INDIA	252.00	303 00	427 00	522 00
Singareni	30 20	36 00	39 00	42 50
TISCO/ISCO/DVC	6.45	7 00	7 00	7 40
ALL INDIA Production	**288.65**	**346.00**	**473.00**	**571.90**
DEMAND	***325.00***	***440.00***	***557.00***	***711.90***
GAP	***36.35***	***94***	***84***	***140***

Source: Coal India (As per the IX plan working group on coal)

Coal India has revised its plans and finally will produce only 252.00 million tonnes during the current year. With 30 million coming from SCCL and 6 45 millions from captive mines, the total adds up to only 288.65 million tonnes, thus leaving an unmet demand of about 36 35 million tonnes. It was hoped that this will come from captive mining blocks allotted to the private power producers but due to various reasons this has not materialized. This gap will continue to increase and in the year 2011 it will become 140 million minus the quantity produced, hopefully by the private sector. Coal India needs to more than double its production in 2011-12 which is quite ambitious given the present investment scenario. Table xviii gives the estimate of production contribution from different categories of projects in 1996-97. The contribution from the new projects is only 7% of the total and is likely to go down as the investment in new mining projects has been meager in the last five years.

Table xviii Estimated category-wise production contribution in 1996-97

	Exiting mines	Ongoing Projects	New projects	Total	Original plan
CIL	128	106	18	252	270
SCCL	13	14	3	30	33
TISCO/ISCO/DVC	6	-	-	6	5
Total	147	120	21	288	308

Source: Ministry of coal

Transport issues

Coal movement

Rail, road and MGR modes constitute the most important means of coal dispatches to various consumers but among them rail is and will remain as the main mode of transport of coal in the country The share of rail in the total coal movement has declined from 78% in 1977-78 to 54% in 1995-96 and this reduction is mainly due to the pit-head power stations which take coal by MGR, which has increased from 2% to 21%. In the future, the share of coal movement is projected by railways at 64% by 2001-02. The coal quantities to be moved as projected by railways increase from 194 Mt in 1996-97 to 243 Mt in 2001-02 and 420 Mt in 2011-12. The railways are already implementing various plans to meet the coal movement projections for 2001-02 Beyond 2001-02, there will be constraints in coal movement from North Karanpura, Korba, Talcher and Ib Valley coalfields where production increases are very large (Table xvii).

The coastal movement has been increasing consistently over the years with increasing demand from coastal power stations. In 1995-96 more than 10 million tonnes have moved by this route compared to about 9 million in 1994-95. It is programmed to grow but is dependent on the extent of new capacity addition for coal transport to Paradeep, Vizag and handling at the ports.

Presently the share of railway in total movement of coal is about 54% and is likely to grow to 64 % by 2001-02. The share of rail transport as per different projections of demand and IR's projections are given in Table xix

Table xiv Coal demand and share of rail transport (Mt)

	1996-97	2001-02	2006-07	2011-12
Working Group's coal demand estimate	325	440	557	711
Rail transport share as per WGC	195	282	356	455
TERI's estimate				
Energy conservation scenario	300	353	438	554
Rail transport share	180	226	280	355
Railway's estimate	194	243	325	420

As against the demand projection of 325 in 1996-97 by WGC, the rail transport share @ 60% is about 195 Mt. IR has projected 194 Mt as the coal traffic in 1996-97 in their annual plan. However, as per TERI's demand projection, it is only 180 Mt. For year 2001-02, the projection by IR is 243 Mt which is adequate as per the projection of TERI at 226 Mt. The projections for the years 2006-07 and 2011-12 are roughly estimated at 325 Mt and 420 Mt by the railways against TERI's projected requirement of rail transport needs of 280 and 355 Mt respectively.

Inter-modal split for future coal movement up to 2001-02

Since power plants are the largest consumer of coal, the coal movement plans would depend mainly on the location of future power plants. The pit-head power plants would draw coal through captive modes like MGR/own wagons, but the distant power plants would have to depend on rail and rail-cum-sea modes for coal movement It is also assumed that road movement would not increase in the future from the levels of 1993-94, since they are costly, except for short lead destinations. Rail however, would continue to remain as the most important mode and its share increases from 54% in 1996 to 64% in 2011

Areas requiring special thrust are improvements in rail and port infrastructure to augment off-take from Korba, Ib Valley, Talcher and North Karanpura coalfields, augmentation of coal capacities in congested routes such as main line beyond Mughal Sarai, main line beyond Chkradharpur and East coast line beyond Cuttack, etc.

Coastal movement

Coastal shipment has emerged as an important mode of coal movement. It serves primarily to reduce rail leads after coal is initially carried from pit-head to linked ports. Haldia, Paradip and Vishakapatnam ports are shipping coal for Tuticorin and other consumers in south. The details of coal handling ports are given in Table xx. Many of the ports are already handling cargo more than their designed capacities. There are expansion plans for Paradip port to handle the increased volume of coal flows from Talcher coalfield Since coastal movement has to increase for meeting the needs of consumers in the southern states, the coal handling capacities at Paradip and Vishakapatnam have to be substantially increased.

Table xx Major ports capacity and traffic handled in 1993-94 (Mt)

Port	Capacity		Traffic handled	
	All commodity	Only coal	All commodity	Only coal
Calcutta	6.75	-	5 17	
Haldia	16.78	5.00	13.33	5.43
Paradip	7.65	NA	8 33	4.69
Vishakapatnam	23 35	NA	25 59	6.58
Madras	22 07	NA	26.54	5.87
Tuticorin	5 10	3 00	6 70	3.81
Cochin	10 66		7.62	
New Mangalore	9 55		8 63	
Mormugao	15.92		18.72	
Bombay	26 80		30.74	
Kandla	20.80		24.50	
JL Nehru	5.90		3.39	
Total	171.03	8 00	179.26	26 43

Source: Ministry of surface transport

Oil and natural gas reserves in India

The total area of oil bearing sedimentary basins in India is about 1.72 million sq. km, comprising of 1.4 M sq km onshore and 0.32 M sq. km offshore within the 200 m Isobath line. This has a total of 26 basins, 13 of which are of geological interest. The prognosticated resources of oil and oil equivalent of gas were estimated at 5.6 Bt in 1964, which has increased to 21.3 Bt in 1992. The reserves of oil and gas, which fall in the recoverable category are only around 5.9 Bt (1/91). The total balance recoverable reserves of oil and gas have grown to 765 Mt and 707 BCM respectively in 1995. The details are given in Table xxi.

Table xxi Oil and gas reserves

Crude Oil	Mt	Natural Gas	BCM
Onshore			
Gujarat	153 40	Gujarat	92.13
Assam	156 06	Assam	156 18
TOTAL	309 46	Rajasthan	3.82
		TOTAL	252.13
Offshore			
Bombay High	455 17	Bombay High	454.56
TOTAL	764 63	TOTAL	706 69

Source: Petroleum statistics 1995

Oil and natural gas production

India is a net oil importing country, whose oil import bill is increasing every year due to increased demand and stagnant production. Production of crude oil rose from 6 8 Mt in 1970-71 to 34.5 Mt in 1995-96. Natural gas production has increased from 1.45 BCM in 1970-71 to 22 BCM in 1995-96. This increase has largely been due to an accelerated production from the Bombay High off-shore basin. The details are given in Table xxii and Table xxiii

Table xxii Production of crude oil and natural gas

Crude Oil (Mt)	1980/81	1990-91	1994-95	1995-96
Onshore				
Gujarat	3.808	6 398	6 279	6.416
Assam/Nagaland	1.712	5 076	5 043	5 043
Arunachal Pradesh	0.002	0 043	0 035	0.28
Tamil Nadu/ A P	-	0 313	0 656	0.423
TOTAL	5.522	11 830	12 013	11.910
Offshore	4.985	21 191	20 226	22.645
GRAND TOTAL	10 507	33 021	32 239	34.555
Natural gas - gross (BCM)				
Onshore				
Gujarat	0.842	1 696	2 462	2.890
Assam/Nagaland	0.843	2 011	1 909	1 881
Arunachal Pradesh	-	0 029	0.037	0.032
Tripura	-	0 070	0.097	0.130
Tamil Nadu/ Andhra Pradesh	-	0.110	0 738	0.796
TOTAL	1 685	3.916	5 243	5.729
Offshore	0.673	14 082	14.138	16.579
GRAND TOTAL	2.358	17 998	19.381	22.308

Source: Indian petroleum and natural gas statistics

Table xxiii Gross and net production of natural gas (BCM)

	1970/71	1980/81	1990/91	1994-95
Gross production	1 445	2 358	17 998	19 381
Onshore	1.445	1.685	3.916	5 243
Offshore	-	0 673	14 082	14 138
Gas re-injected	0 036	0 067	0 102	0 023
Onshore	0 036	0 067	0 102	0 023
Offshore	-	-	-	-
Flared	0.762	0 769	5 130	2 019
Onshore	0.762	0 403	1 083	0 979
Offshore	-	0 366	4 047	1 040
Net production	0.647	1 522	12 766	17 339
Onshore	0.647	1 215	2.731	4.189
Offshore	0	0 307	10.035	13.150

Source: Indian petroleum and natural gas statistics

Policy on natural gas

Natural gas based power plants are cheaper to construct, have low gestation period, are easy to operate at much higher capacity levels, more energy efficient, work on a higher PLF, and can be started and stopped at short notice and thus have lower cost per unit of generation. Thus they are ideal for meeting the peak load demands. Similarly, gas is a preferred fuel for industrial and commercial sectors due to its higher efficiency, no storage cost, higher output and better quality of product especially in glass industry. However, the use of gas in these sectors, domestic included, has been restricted due to limited availability.

All allocation of natural gas to consumers are made by an inter-ministerial Gas Linkage Committee. This committee also decides the reallocation in situations of temporary shortages in production and supply. There has been no significant allocations since 1990, as allocations were made to prospective consumers, based on optimistic estimates of the availability of natural gas for the next 15-20 years which did not materialize and there is no indication of its materialization in future To bridge the demand supply gap, national and international private companies have been awarded gas fields but the availability from these is likely to be low as none of them have acquired large properties needed for exploration.

Table xxiv Projected availability of natural gas (MMSCMD)

Within Country	1996-97	1999-00	2004-05	2006-07
Indigenous Gas	64	72	72	72
CBM*	0	0	12	14
Total	64	72	84	86
Imports				
Through Pipeline #				
Oman	0	0	28	56
Iran	0	0	0	25
As LNG	0	2	10	20
Total availability	64	74	122	187
Demand	88	147	187	188
Deficit	24	73	65	1
Deficit now estimated	24	73	105	96

Source: Ministry of Petroleum and Natural Gas

The probability of imports through pipeline has become remote due to various political, technical and commercial reasons and thus the deficits will increase to that extent. The progress of award of lease to private companies for exploration of CBM has been tardy and as a result, till date, no one is exploring for it. Even if things start looking up on this front, possibility of CBM being available for use by 2004-05 seems remote as the number of holes to be drilled is very large and time consuming. Also, since exploration for BCM has not yet been done, the views on its potential are divergent. The total availability, thus is from the indigenous sources pegged at 72 MMSCMD only. Additionally, some imported LNG may

be available by 2005-06 if the terminals come in place. Looking at this current deficit of more than 100 MMSCMD, possibility of more indigenous natural gas going to power generation looks remote. Thus, assuming that no further indigenous natural gas or CBM will be available for power generation, the only possibility is that of imported LNG and naphtha - imported and indigenous.

During early 90's, Planning Commission took a conscious decision for use of natural gas in fertilizer sector as power sector could use coal, which was otherwise available in abundance. Only 30 % of the total gas production was allocated to power sector for the gas turbines in different states. The possibility of more gas being available, as stated earlier, is ruled out.

Table xxv Demand for natural gas (MMSCMD)

State	Fertz	Power	Sponge Iron	Glass	Others	Total
TOTAL MMSCMD	56	70	30	62	44	262
TOTAL BCM	21	26	11	23	16	96

Source: GAIL 20/5/96 150 MMSCMD - 55 BCM/day

Table xxvi Long term demand for NG (MMSCMD)

	1999-00	2004-05	2009-10
Power	43.43	72 01	156.06
Fertiliser	29 89	29 89	29 89
Sponge iron	7 44	12	15
Industry	57 57	62 09	67 13
Domestic	2 11	4.16	5 5
Internal use/ shrinkage	6.1	7 73	10 32
Grand Total	146 54	187 88	283 9

Source: Planning Commission 20/5/96

Import of LNG

The middle east countries have large reserves of gas, amounting almost to one third of the worlds reserves. Leading among them are Iran, Qatar, Saudi Arabia etc. Other country in the region are Indonesia, Myanmar and Malaysia. Many of these countries are expanding existing capacities and creating new grassroot LNG capacities. These are some potential sources for import of LNG for east and west coasts and the cost of such import may vary between US$ 3.5 to 5 per MMBTU.

Cost of thermal power generation from all fuels

A recent study (1996) conducted by TERI shows that on an average, in Southern India on east and west coast, the unit cost of power generation for different fuels is as shown in Table xxvii. These costs are for a location at the coast and will be higher if the fuels are transported inland.

Table xxvii Cost of power generation using different fuels

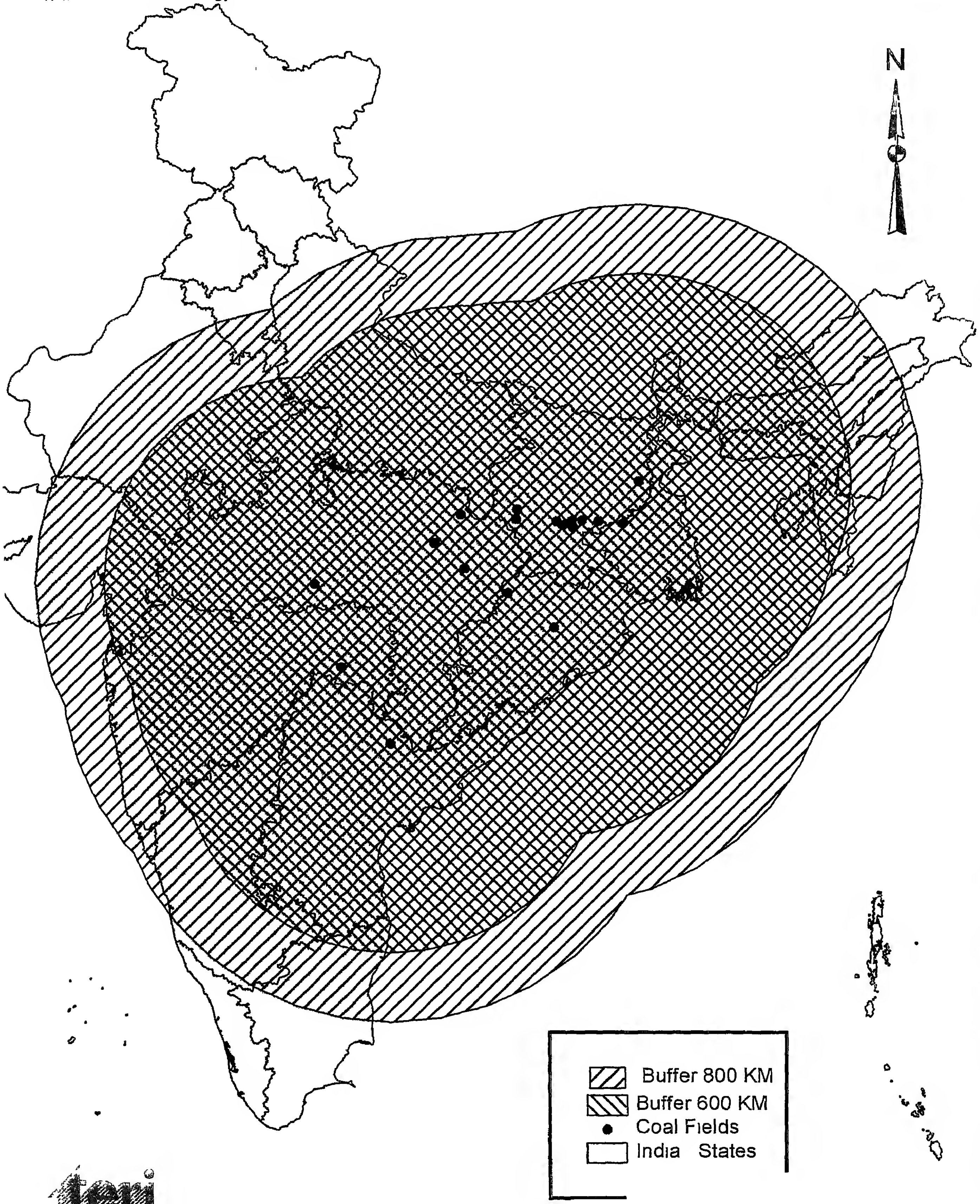
Fuel option	Rs per kWh
Imported LNG	2 23
Imported Coal	2 20
Indigenous Naphtha	2.01
Indigenous Coal	1.98
Imported Naphtha	1 93
Indigenous Natural Gas	1 68

Source: Shell study TERI 1996

Indian coal can remain the only source of power generation all over the country only when the power cost per unit of generation from other fuel sources are higher. An analysis shows that the indigenous coal can be very competitive within a distance of about 800 km from the production source. For a 500 MW unit, situated within 800 km and using grade E coal can produce an unit at about Rs 2.23. Beyond this distance, all other fuels will compete with coal depending on their availability. However, infrastructure for movement of fuels may become a problem in these cases. Natural gas is by far the cheapest due to its administered price. Imported and indigenous naphtha also compete with Indian coal The lowest cost of Rs 1.68 per kWh by using indigenous gas can be matched by coal within a distance of less than 600 km from the production center. The graphic representation of this result is shown in Figure 1. It evident that except at southern west coast, where other fuels become cost effective, coal remains the only option in all other parts of India. In northern parts of the country, coal and other fuels have to compete with each other on the basis of the transportation distance, from port for other fuel and beyond 800 km for indigenous coal. Assam has been excluded from this presentation for clarity. This result is valid only on the assumption that the coal moves to the power house from the nearest coalfield.

Finally

India has no alternative but to produce more coal in the short and medium term to meet the ever increasing demand for energy sources. Coal is the only resource which is available in abundance and can be used by various industries in its raw form, as feed stock or for producing steam or gas, which in turn can be used to produce electricity to meet the increased demand. All other fuels available in India are low in reserves and are being imported to meet the demand with obvious foreign exchange implications. Using cleaner technologies in the use of coal, often known as the dirty fuel, can be made more environment friendly.



*Assam CF not considered for clarity

Fig 1 Coal competitiveness - Zone of influence

CHAPTER 1

Preamble

Any country's objective should be to arrange for adequate sustainable energy at acceptable costs to be supplied to meet the needs of all, using optimal production and end-use efficiency, while achieving socially acceptable care and protection of the environment.

For developing countries, the key issues are economic growth, access to adequate commercial energy supplies and the finances needed to achieve this, and India is no exception

The consequence of the huge forecasted increase of global population will be the accelerated consumption of the reserves of fossil fuels, with coal depleting less rapidly than oil and natural gas. The result will be increased reliance on coal.

Coal reserves

The known coal reserves of the world are spread over 100 countries At current level of production, these reserves will last for more than 230 years. The coal reserves of some selected countries, which together account for 90% of the world reserves are given in Table 1.

Table 1. Proved coal reserves (end 1995) selected countries and world (Mt)

Countries	Anthracite & bituminous	Sub-bituminous & Lignite	Total	Share of total (%)	R/P ratio Years
USA	106495	134063	240558	23.3	258
Canada	4509	4114	8623	0 8	115
France	113	26	139	< 0 05	17
Germany	24000	43300	67300	6 5	273
Poland	29100	13000	42100	4 1	212
United Kingdom	2000	500	2500	0.2	48
Total Former Soviet Union	104000	137000	241000	23 4	> 500
South Africa	55333	-	55333	5.4	272
Australia	45340	45600	90940	8.8	375
China	62200	52300	114500	11.1	88
India	**68047**	**1900**	**69947**	**6.8**	**245**
TOTAL WORLD	519358	512252	1031610		228

Source: BP Statistical Review of World Energy 1996

Oil and gas reserves

The worlds total oil and gas reserves at the end of 1995 stood at 138 thousand Mt and 140 trillion cu m. and is expected to last for about 40 and 60 years respectively at the current rate of production. 70 % of reserves of oil and gas are in Middle East and CIS. The reserves of Oil and natural gas of some selected countries accounting for 80 % of the world's proved reserve is given in Table 2 and Table 3.

Table 2. Proved oil reserves - selected countries and world

Country	'000 Mt	Share of total reserves (%)	R/P ratio
OECD	14 0	10.2	14.7
Former Soviet Union	7 8	5.5	22.0
Iran	12.0	8.7	65 9
Iraq	13 4	9.8	> 100
Kuwait	13 3	9.5	> 100
Saudi Arabia	35 7	25.7	83.8
UAE	12.7	9.7	> 100
India	**0.8**	**0.6**	**20.9**
TOTAL WORLD	138.3		42.8

Source: BP Statistical Review of World Energy 1996

Table 3. Proved Gas reserves - selected countries and world

Country	Trillion cubic meter	Share of total reserves (%)	R/P ratio
OECD	13 9	10 0	14.4
Former Soviet Union	56.0	40.0	80.4
Iran	21 0	15 0	> 100
Iraq	3 1	2.2	> 100
Kuwait	1.5	1.1	> 100
Saudi Arabia	5.3	3 8	> 100
UAE	5 8	4 1	> 100
India	**0.7**	**0.5**	**37.8**
TOTAL WORLD	139.7		64.7

Source: BP Statistical Review of World Energy 1996

Coal production

The total Hard coal production worldwide was 3317 Mt in the year 1995 and is projected to be 4152 Mt in the year 2000. Some of the major Hard coal producing countries with their production is shown in Table 4 These countries together contribute more than 90 % of the world's hard coal production.

Table 4. Coal production - selected countries and world

Country	Million Tonnes oil equivalent					Million tonnes	
					Share of total (%)	Hard coal	Lignite
	1991	1993	1994	1995	1995	1995	1995
USA	539.9	505.5	551.7	547 8	24.6	577 1	357.0
Canada	40 0	37.7	39 5	41.0	1.8	38.6	36.3
France	7.4	6.3	5.5	5.1	0 2	7.0	1 4
Germany	102.2	83.4	76 8	74 6	3.4	53.6	192.8
Poland	90.6	85 0	86 6	86 8	3.9	135.3	63 5
United Kingdom	57.3	41.5	29 8	32 0	1 4	52 6	–
Former Soviet Union	297.4	255.4	225 1	203 8	9 2	332 0	100 5
South Africa	94 4	96.5	103.7	107.8	4.8	203 5	–
Australia	110 7	117.7	119.1	125.9	5.7	194.7	48 1
China	545 1	580 7	625.6	655.5	29 5	1253.4	44 6
India	**110.9**	**121.5**	**124.6**	**131.0**	**5.9**	**263.5**	**22.0**
TOTAL WORLD	2208.7	2142 5	2197.1	2225 1		3316.6	1213 8

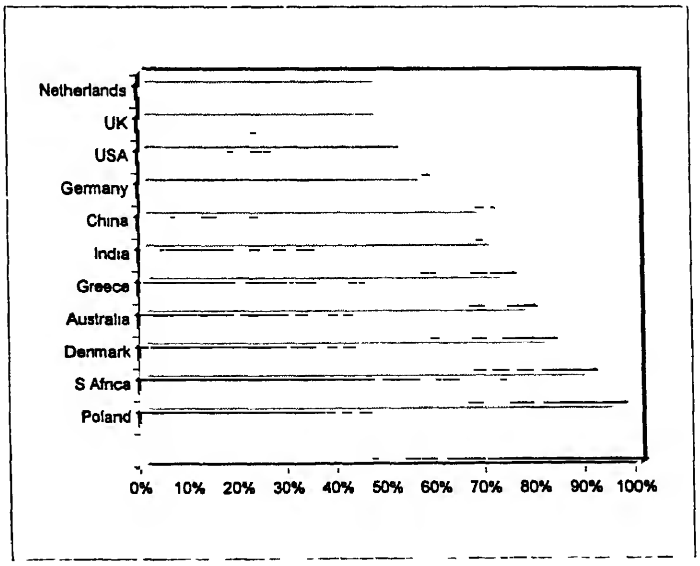
Source: BP Statistical Review of World Energy 1996

Coal as major fuel for electricity generation

Coal is the major fuel used for generating electricity, providing some 40 % of the world's electricity. Some of the countries heavily dependent on coal for electricity generation (1994) are listed below.

Coal is the major fuel for electricity generation

Poland	96 %
S Africa	90 %
Denmark	82 %
Australia	78 %
Greece	74 %
India	71%
China	70 %
Germany	57 %
USA	53 %
UK	48 %
Netherlands	48 %



Per capita primary energy consumption

The per capita Primary Energy Consumption of some of the countries in the world is produced in Table 5.

Table 5. Per capita primary energy consumption

Country	tonne of oil equivalent
USA	7 77
Canada	7 67
Australia	5.02
Russian Fed	4 52
Japan	3 83
EU-12	3.58
S Korea	3.00
China	0 62
India	0 23

1 tce - tonne of coal equivalent = 0 697 toe - tonne of oil equivalent

Source: IEA publications, UN-ECE BP statistical Review

India vs world

Reserves of hard coal and lignite in India is 6.8 % of the total world reserves with a R/P ratio of 245 Compared to this, the oil and gas reserves are only 0.6 % and 0 5 % with R/P ratio of 21 and 38 respectively. It is, therefore, logical that India will put more stress and reliance towards mining and utilization of coal to meet its primary energy needs compared to oil and gas and for that matter any other energy resource.

In India per capita consumption of energy is only 0.24 toe as against the world average of 1 toe and much higher levels in developed countries. The per capita consumption of energy is likely to rise and though it may not come anywhere closer to that of developed countries, it will definitely see a steep increase in the next 10 -15 year span resulting in increased demand of energy. At the projected population of 1196 million and projected consumption of energy resources at 468 Mtoe in the year 2011-12, the per capita consumption will reach a figure of 0 4 toe.

CHAPTER 2

Energy reserves in India

Coal reserves

India is relatively well endowed with both exhaustible and renewable energy resources. Coal is the major exhaustible energy resource in the country and has a life expectancy of over 200 years The total coal reserves have been assessed at about 202 Billion tonnes(Bt) of which 70 Bt (about 35%) are proved reserves. The details are given in Table 6.

Table 6. Indian coal reserves (0-1200 m) on 1.1.1996 (Bt)

Category	Geological reserves			
	Proved	Indicated	Inferred	Total
Prime coking	4.2	1 1	-	5 3
Medium coking	10.3	11 5	1 1	22 9
Semi coking	0 4	0 7	0 5	1 6
Total coking	14 9	13 3	2.6	29.8
Non-coking	55.5	76 4	40.2	172 1
TOTAL	70 4	89 7	41.8	201 9

Source: GSI 1996

The salient features of coal reserves are as follows·

- About 63% of the total coal reserves occur within 300 m depth and 26% occurs in the depth range from 300-600 m depth Only about 10% reserves occur beyond 600 m depth in deep coal basins like Jharia and Raniganj coalfields.
- Coking coal reserves are only 15% of the total coal reserves, confined to only 10 out of the 62 coalfields in Bihar, West Bengal and Madhya Pradesh.
- Reserves of non-coking coals amount to about 85% of the total reserves of which only 12% are of superior grade and occurring mostly in Raniganj.
- Therefore, it can be concluded that bulk of the coal reserves (73%) are inferior grade non-coking coals occurring in thick inter-banded seams and located in coalfields like Singrauli, Talcher, North Karanpura, Rajmahal, Ib Valley and Korba, etc.

The power grade coal comprising grades E, F & G of non-coking coal is estimated to be 40.9 Bt Large proportion of this reserve is in shallow deposits and thus amenable to open cast mining

Lignite reserves

The total resources are estimated at about 24 Bt of which about 90% are located in Tamil Nadu, 6% in Rajasthan and 4% in Gujarat. Some lignite deposits are also found in Jammu & Kashmir and Kerala. The details are given in Table 7.

Table 7. Reserves of lignite in India (Bt)

State	Reserves			Total
	Proved	Indicated	Inferred	
Tamil Nadu	2.10	2 93	16 78	21 81
Rajasthan	0.07	1 06	0 26	1 39
Gujarat	0.30	0.57	0 06	0 93
Jammu & Kashmir	-	0.02	0.11	0 13
TOTAL	2.47	4 58	17 21	24 26

Source: GSI 1996

Oil and natural gas

The total area of oil bearing sedimentary basins in India is about 1.72 million sq. km, comprising of 1.4 M sq. km onshore and 0.32 M sq. km offshore within the 200 m Isobath line. This has a total of 26 basins, 13 of which are of geological interest. The prognosticated resources of oil and oil equivalent of gas were estimated at 5.6 Bt in 1964, which has increased to 21 3 Bt in 1992. The reserves of oil and gas, which fall in the recoverable category are only around 5.9 Bt (1/91). The total balance recoverable reserves of oil and gas have grown to 765 Mt and 707 BCM respectively in 1995. The details are given in Table 8

Table 8. Oil and gas reserves

Crude Oil	Mt	Natural Gas	BCM
Onshore			
Gujarat	153.40	Gujarat	92.13
Assam	156.06	Assam	156.18
		Rajasthan	3 82
TOTAL	309.46	TOTAL	252.13
Offshore			
Bombay High	455.17	Bombay High	454 56
TOTAL	764.63	TOTAL	706 69

Source: Petroleum statistics 1995

Hydroelectric power

According to the Central Electricity Authority (CEA), the hydroelectric power potential in the country is estimated at about 84,000 MW of which about 75% is confined to the northern and north eastern region A regional break-up of the hydro potential is given in Table 9. The table also gives the potential developed and under development in the different regions.

Table 9. Hydro potential

Region	HE potential at 60% PLF MW	HE potential developed MW	%	Under development MW	%
Northern	30155	3955	13	2173	7
Western	5679	1764	31	1352	24
Southern	10763	5260	49	1112	18
Eastern	5590	850	15	735	13
North East	31857	253	1	360	1
TOTAL	84044	12082	14	5732	7

Source: Review of Hydro Power Performance 1994

Nuclear power

Uranium and thorium are basic resources for generation of electricity through fission based technology India has assured uranium resource of 34,000 tonnes of U308 of which 15,000 tonnes are economically exploitable, which is enough to support the additional capacity. There are vast resources of thorium estimated at 3.63 lakh tonnes available along the sea coast and a few islands

Renewable energy resources

Among the various renewable energy based technologies (RETs) available, only the following hold promise as supplementary sources for commercial power generation

Wind power

Wind farms appear to be one of the most feasible and cost effective mode for supplementing the conventional means of power generation on a moderate scale. The technical viability of the wind farms have been established in India. ~~750~~ 500 MW capacity wind farms are already in operation and another ~~1800~~ 1500 MW are in various stages of planning in the coastal states of Tamil Nadu, Gujarat, Andhra Pradesh, Kerala, Karnataka and Madhya Pradesh in central India. Estimates of the Ministry of Environment and Forests (MNES) place the realizable wind energy potential in India at 20,000 MW. There is, however, a significant difference

between the ultimate and the realizable potential of wind energy and this is largely due to the highly intermittent nature of wind energy source and the characteristics of the grid.

Small hydro power

In India, the small, mini and micro hydel systems together are treated as small hydro power (SHP) systems covering a wide range of sizes and capacities. Presently, the responsibility of promoting MMHP up to 3 MW lies with MNES while the CEA looks after hydro power from 3-15 MW. The classification adopted is as follows:

Micro-hydro:	Less than 100 kW
Mini-hydro:	101-2,000 kW (unit size up to 1 MW)
Small-hydro:	2,001-15,000 kW (unit size up to 5 MW)

MNES estimates that the total small-hydro potential for India up to 15 MW capacity is like to be over 10,000 MW. About half of this is expected to be in mini and micro hydro categories in the hilly areas and in the north-eastern region.

Biomass energy

An overwhelming proportion of the rural domestic energy is supplied by the biomass fuels. In the rural areas, biomass fuel is mostly collected at a zero private cost, and no formal distribution systems exist like in the case of commercial fuels. Hence, it is difficult to correctly estimate, either at the micro or macro level, how much biomass is supplied from what type of land. This process is rendered even more difficult in the absence of reliable biomass assessment techniques for large-scale enumeration

Bagasse based cogeneration

Several energy intensive industry categories such as sugar, paper, textile, and fertilizer generate their steam requirements internally and also purchase electricity from the grid. Cogeneration of electricity and steam offers increased system and fuel efficiency to the industry. It reduces industry demand for utility power and the additional surplus, if any, could be sold to utilities. Cogeneration, thus, provides an alternative to utility power and reduces the overall demand load on power sector.

While cogeneration systems are in use in some of the paper, pulp and fertilizer industries in India, there are little efforts to optimize the steam and electricity requirements for various reasons These include company investment criteria, unavailability of equipment, concerns about incremental costs, and above all government regulations.

Significant cogeneration potential has been identified in the Indian industrial sector. The National Productivity Council carried out a macro study in 1979 on the feasibility of cogeneration in Indian industries and estimated a potential of 421 MW in 28 of the 150 industrial units surveyed. It also estimated that over 1,500 MW of additional power could be generated with marginal investments in cogeneration systems. A study carried out by the Inter-ministerial Working Group in 1983 estimated that the economic potential for cogeneration in the major industries in India is about 1,500 MW. More recently, a study carried out by TERI in 1993, based on a detailed survey of 300 industrial units, estimated a total cogeneration potential of about 7,500 MW, of which the sugar industry alone was estimated to account for over 65% of the total identified cogen potential. Substantial potential also exists in the textile and paper industry Regional breakup is given in Table 10.

Table 10. Cogeneration potential in India (MW)

Region	1996	2001	2006	2011
Northern	2,823	4,026	5,910	8,472
Western	2,303	3,275	4,756	6,766
Southern	3,731	5,301	7,755	11,093
Eastern	1,178	1,698	2,501	3,593
North-eastern	35	50	75	109
TOTAL	10,070	14,350	20,997	30,033

Source: TERI

Demand side management

- The Inter-Ministerial Working Group on energy conservation has estimated that there is a potential of 20%, 20% and 15% energy savings in coal-based, oil-based and electrical equipment respectively, in the existing system. This will be achieved by the installation of heat recovery systems, replacement of inefficient boilers, computerization of process control operations, adoption of cogeneration systems and use of energy efficient equipment and lighting in domestic and commercial sectors
- There has been a lot of efforts to spread awareness to save energy via the demand side management The success of DSM will depend on an active involvement of the producer and the consumer, which, in India is lacking because the distribution, billing and realization of the dues has not been the ideal resulting in total disinterest of the consumer. Some electricity boards have started taking steps in the right direction and Orissa has shown the path In Orissa power restructuring scheme, DSM has a big role to play. However, the experts in this area do not see miracle happening in the next ten to fifteen years

- An estimate of generation through renewables by the experts suggest that about 10,000 MW of generating capacity will be created using micro hydel and wind energy, and solar power during this time frame out of which about 400 MW of small hydro and 500 MW of wind energy is already in place. Recently, Rajsthan Govt. has entered into agreement with several PPPs for production of solar energy to the tune of 300 MW.
- Generation through other technologies like ocean thermal, sea wave power and tidal power are not expected to add anything to the total generation by 2011.

Summary of renewable energy technology potential

The potential of Biomass based power, small hydro, wind and ocean related power together is projected at 1,26,000 MW Not more than 10 to 20 % of this will be exploited by 2011 due to various reasons. Total installed capacity today is a meager 1000 MW.

The potential of all RETs are listed in Table 11.

Table 11. Renewable energy potential

Source/technology	Units	Potential/ availability	Potential exploited
Biomass based power	MW	17,000	100
Solar energy	Whr/year	$5x10^9$	-
Small hydro	MW	10,000	400
Wind energy	MW	20,000	500
Ocean thermal	MW	50,000	Nil
Sea wave power	MW	20,000	Nil
Tidal power	MW	9,000	Nil

Source: TERI

CHAPTER 3

Energy production and supply

Background

The economic reforms process, currently underway in India, would largely dictate the long-term development path of the country. The importance of the energy sector as an input to development is well known and the supply of electricity is a critical input to economic growth. Accordingly, the plan allocation of funds for the power sector increased sharply from about 18% in the past to over 28% in the 7th Plan. Coal contributes to about 70% of the total power generation in the country.

Energy production and supply

Commercial sources of energy (coal, oil and natural gas, hydro and nuclear) account for nearly 60% of the total energy supplies, while non-commercial sources (fuel wood, biomass) make up the balance Given the large resources of coal, it dominates the commercial energy supply profile.

Coal

Coal industry was nationalized in two stages viz coking coal mines were taken over in October 1971 and all other coal mines in January 1973. This was done, apart from other considerations, with a view to ensure that the production of coal which is the primary source of energy should be properly planned to meet the increasing requirements in the industrial development of the country. It was expected that nationalization of the coal industry would also ensure fair and equitable distribution of coal to meet the essential needs of users, both in the core and non-core sectors

To ensure sustained and planned development of all facets of the coal industry, massive investment to the tune of about Rs 18,000 crores has been made since nationalization in opening up of new mines, re-organization of existing mines and development of associated infrastructure. Coal production has registered an annual growth rate of about 4.3% since nationalization, increasing from a level of 73 Mt in 1970-71 to 270 Mt in 1995-96. In the post-nationalization period, major thrust was given towards development of new outlying coalfields like Rajmahal, North Karanpura, Singrauli, Korba, Ib valley and Talcher. These coalfields contributed 43% of the total coal production in 1994-95. Consequent upon development of new coalfields in outlying areas, a large number of pit-head

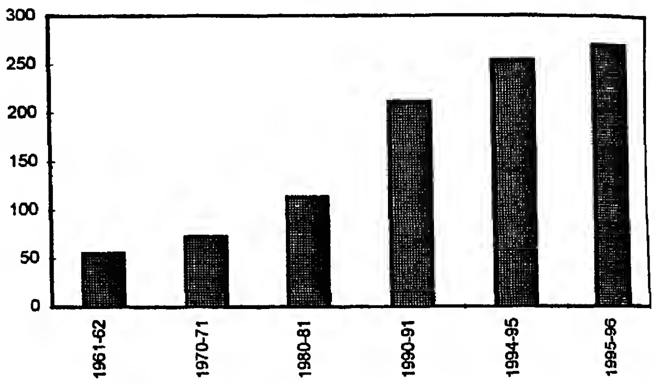
super thermal power stations have come up. This has helped in reducing the load on railways as most of these pit-head power stations transport their coal by captive modes such as merry-go-round (MGR) system. The production, dispatch and closing stock from 1970-71 to 1995-96 are given in Table 12.

Table 12. Production dispatches and stocks of coal (Mt)

Year	Production	Dispatches	Closing stocks
1961-62	55 23	50.81	3 7
1970-71	72.95	62.26	9.5
1980-81	113.91	105.76	18.28
1990-91	211.73	201.07	42.56
1994-95	253.73	248.43	46.40
1995-96	270.12	267.00	37.55

Source: Ministry of Coal

Graph 2. Trend of coal production (1961-96)



The large increases in production could be achieved through enhanced investment in the coal industry by the government, deliberate shift in technology, increased emoluments and welfare amenities for coal workers and other measures. The Government adopted a deliberate policy to increase production through opencast mines to meet the increasing demand of coal for the utilities. The opencast mines which contributed only about 28% of the total production at the time of nationalization (1973) increased their share to about 72% in 1995-96. The major factors in favour of opencast mines are shorter gestation period, high recovery and safety, and lower cost of production. However bulk of coal produced from opencast mines is inferior grade coal As a result of this policy, the production of inferior grades of both coking and non-coking coal have been increasing in the last two decades and this trend is continuing. The details of technology-wise and type-wise production are given in Table 13 and Table 14.

Table 13. Technology-wise coal production (Mt)

Year	Underground Mt	%	Opencast Mt	%	Total Mt
1970-71	58.2	80	14 7	20	72.9
1980-81	73 3	64	40.7	36	114.0
1994-95	76 1	30	177.7	70	253.8
1995-96	74 0	28	196.1	73	270 1

Source: Ministry of Coal

In 1970-71, 24% of total coal produced was coking and 76% was non-coking. The production of the non-coking coal over the years have increased sharply, mainly due to the increasing demand of power coal and now it stands at 84%. The percentage of coking coal production in total production has declined to 16% during the same period Moreover, not all coking coal is used for metallurgical purposes and 45% of coking coal production is again consumed by other industrial sectors including power.

Table 14. Type-wise coal production (Mt)

Year	Coking Mt	%	Non-coking Mt	%	Total Mt
1970-71	17 8	24	55.1	76	72.9
1980-81	26 8	24	87 2	76	114 0
1994-95	41 97	17	211 76	84	253 73
1995-96	42.92	16	227.20	84	270.12

Source: Ministry of Coal

In the non-coking coal production, the share of superior quality coal (Grades A, B C & D) in 1970-71 was about 80% which has declined in 1995-96 to about 50% The balance 50% was inferior grade non-coking coal (Grade E, F & G). This declining trend in the production of superior grades is likely to continue in the future.

Coalfields like Jharia, West Bokaro, East Bokaro and Ramgarh produce largely coking coals Raniganj, South Karanpura, Patherkhera, Pench Kanhan, Korba, Central India and North East Coalfields produce all the superior quality non-coking coal. Bulk of the inferior grade non-coking coal production comes from Rajmahal, North Karanpura, Singrauli, Wardha, Korba, Ib valley, Talcher and Singareni coalfields. Out of these Wardha, Rajmahal, Singrauli and Singareni are almost fully committed to pit-head power stations. The coal demand of distant power houses are largely met from North Karanpura, Ib valley, Talcher and

Korba coalfields. The Bihar-wise coal production in 1984-85 and 1994-95 is given in Table 15.

Table 15. Coalfield-wise coal production (Mt)

Coalfield	1984-85	1994-95	1996-97 (Projection)
Raniganj	17.5	14 71	18 40
Mugma Salanpur	5.1	4 12	4 82
Rajmahal	**0.6**	**6.02**	9 52
Jharia	21 8	28 75	28 24
Giridih	0 7	0.36	0.45
West Bokaro	3.5	3 04	3.73
East Bokaro	8.9	9.50	10.38
Ramgarh	1 3	2.25	2 50
South Karanpura	5 8	4.75	5.29
North Karanpura	**4.7**	**11.41**	12.85
Singrauli	**10.7**	**32.50**	37.00
Wardha Valley	**7.2**	**15.98**	17.71
Umrer	3.1	5 02	2.59
Patherkhera	2.5	2 10	2 57
Pench-Kanhan	3.8	4 14	3 75
Central India	16.4	19.01	20 10
Korba	**11.0**	**30.99**	32.40
Ib valley	**2.0**	**9.39**	12 55
Talcher	**3.4**	**17.93**	23 47
North-East	0.8	1 19	0 80
Singareni	**12.3**	**25.60**	30 20
Others	4 3	5 04	36 65
TOTAL	147 4	253.80	288 65

Source: Ministry of Coal

Lignite

The lignite production has increased from about 4 Mt in 1970-71 to over 19 Mt in 1994-95 Almost 80% of the production is from Tamil Nadu and the balance is in Gujarat. The details are given in Table 16

Table 16. Lignite production (Mt)

State	Company	1970-71	1990-91	1994-95
Tamil Nadu	NLC	3.7	11.8	15 4
Gujarat	GMDC	-	2 4	3 9
TOTAL		3 7	14 2	19 3

Source: Ministry of Coal

Almost 90% of the lignite production in Tamil Nadu is used for power generation at the pit-head and the balance is consumed in cement and other industries in the state In Gujarat, most of the lignite production is consumed by industries.

Oil and natural gas

India is a net oil importing country, whose oil import bill is increasing every year due to increased demand With acceleration in exploratory and developmental drilling, there has been a substantial increase in the production of crude oil and natural gas. Production of crude oil rose from 6 8 Mt in 1970-71 to 34.5 Mt in 1995-96. Natural gas production has increased from 1 45 BCM in 1970-71 to 22 BCM in 1995-96. This increase has largely been due to an accelerated production from the Bombay High off-shore basin.

The amount of natural gas which is flared had been rising and reached high levels in 1990-91, but since then has been declining and is now about 10% of the production. The details are given in Table 17 and Table 18.

Table 17. Production of crude oil and natural gas

	1980/81	1990-91	1994-95	1995-96
Crude Oil (Mt)				
Onshore				
Gujarat	3 808	6 398	6 279	6.416
Assam/Nagaland	1 712	5 076	5.043	5 043
Arunachal Pradesh	0.002	0.043	0 035	0 28
Tamil Nadu/ A P	-	0 313	0 656	0 423
TOTAL	5.522	11.830	12.013	11.910
Offshore	4 985	21 191	20 226	22.645
GRAND TOTAL	10 507	33.021	32.239	34 555
Natural gas - gross (BCM)				
Onshore				
Gujarat	0 842	1.696	2 462	2 890
Assam/Nagaland	0 843	2.011	1 909	1 881
Arunachal Pradesh	-	0.029	0 037	0 032
Tripura	-	0 070	0 097	0 130
Tamil Nadu/ Andhra Pradesh	-	0 110	0 738	0 796
TOTAL	1 685	3 916	5 243	5 729
Offshore	0 673	14 082	14.138	16 579
GRAND TOTAL	2 358	17 998	19 381	22 308

Source Indian petroleum and natural gas statistics

Table 18. Gross and net production of natural gas (BCM)

	1970/71	1980/81	1990/91	1994-95
Gross production	1.445	2 358	17.998	19 381
Onshore	1.445	1 685	3 916	5 243
Offshore	-	0 673	14.082	14 138
Gas re-injected	0.036	0.067	0.102	0.023
Onshore	0.036	0.067	0 102	0.023
Offshore	-	-	-	-
Flared	0 762	0.769	5.130	2 019
Onshore	0 762	0 403	1 083	0 979
Offshore	-	0 366	4.047	1 040
Net production	0.647	1 522	12.766	17 339
Onshore	0 647	1 215	2 731	4.189
Offshore	0	0.307	10 035	13 150

Source: Indian petroleum and natural gas statistics

Fuel substitution

Power sector

Indigenous coal can be substituted by other fuels including imported coal in power sector, subject to techno-economic feasibility. In cement industry, the imported coal can replace to a limited extent the indigenous coal in the southern belt, especially with low availability of appropriate quality indigenous coal and the waival of import duty for coal import against export of cement . The brick industry, though is trying to use other fuels in conjunction with coal, such as fuel wood, will continue to be largely dependent on coal as the main source The possibility of fuel substitution is ruled out in the existing power plants in northern and central India because of the increased cost of inland transportation of imported fuel and in eastern India because of the proximity to the coalfields. However, the plants in south India , both existing and new, clearly have wider options for choosing the fuel While the existing plants in southern India can use imported coal as a sweetener to the maximum extent of about 30%, the new plants can be designed to use imported coal The option of using oil / NG /LNG is also open to these power plants. However, large volume imports of coal are dependent on the port infrastructure, which will need huge capital investment and construction time

The steel industry is already using imported coal to a large extent and will continue to do so because of the shortage of good quality coking coal in India Any substitution of coal in steel industry by other fuels is unlikely but natural gas can be gainfully utilized in the production of sponge iron

The power generation capacity has grown rapidly since independence mainly due to large investments made by the government in successive plans. In-spite of this growth, both peak and energy shortages of varying degrees are prevalent in different parts of the country. During 1994-95, the all India peak and energy shortages were 16.5% and 7.1% respectively.

Installed capacity

The generating capacity of utilities comprises a mix of hydro, coal based thermal, oil/gas based thermal and nuclear plants. The installed capacity, which was about 1,700 MW in 1950-51 has grown to 81,000 MW by 1994-95. The annual rate of growth is about 9.5% during this period. Up to mid 1960s, the thrust was more on developing hydel projects, but, since 1970s, the coal based thermal capacity has shown remarkable increase. The share of hydro power rose to 43% in 1970-71, but has been steadily declining and is about 26% in 1994-95. The share of coal based thermal has increased from 53% in 1970-71 to 71% in 1994-95. The share of nuclear is almost stationery at about 2.5%. Table 19 and Table 20 give the installed capacity and also the annual rate of growth in different periods.

Table 19. Installed capacity (000 MW)

Year	Utilities						Total
	Hydro	%	Thermal	%	Nuclear	%	
1950-51	0.6	35.3	1.1	64.7	-	0.0	1.7
1960-61	1.9	41.3	2.7	58 7	-	0.0	4.6
1970-71	6.4	43.5	7.9	53 7	0.4	2.7	14.7
1980-81	11.8	39.1	17.6	58 3	0 9	3.0	30.2
1990-91	18 8	28.4	45.8	69.3	1.5	2.3	66.1
1994-95	20.8	25.6	58.1	71.6	2.2	2.7	81.1

Source: Economic Survey 1995-96

Table 20. Annual rate of growth of installed capacity (%)

Period	Thermal	Hydro	Total
1950/51-1960/61	9.1	13 1	10 5
1960/61-1970/71	11.8	12.8	12.2
1970/71-1980/81	8.2	6.3	7.4
1980/81-1990/91	9.7	4.6	7.1
1950/51-1994/95	9.7	9 1	9.5

Source: CMIE, 1991

Almost 71 % of the total capacity available in 1994-95 for power generation is that of thermal plants, hydro capacity being only 26% and declining due to various reasons including increase in awareness among the populace about the environmental degradation and large scale displacement of persons. The share of different fuels in the total generation via the thermal route is given in Table 21.

Table 21. Installed Capacity (MW)

Region	Hydro	Steam	Gas	DSL/Wind	Nuclear	Total
Northern	7022	13483	2215	19	895	23634
Western	2814	17212	2366	34	640	23066
Southern	8438	9593	109	144	470	18754
Eastern	1655	9667	190	25	0	11537
North East	490	335	257	73	0	1155
Islands	0	0	0	33	0	33
Total MW	**20419**	**50290**	**5137**	**328**	**2005**	**78179**
Percentage	**26**	**64**	**7**	**0**	**3**	**100.00**
Central Sector	1814	16538	3009	0	2005	23366
State Sector	18310	31471	1869	327	0	51977
Private Sector	294	2281	259	0	0	2834

Source: Annual report Min of Power 30 11.1994

The share of coal based thermal capacity in total thermal generation capacity is 91% in 1994-95.

Power generation

The gross power generation in utilities has increased rapidly from 5.1 Billion kWh in 1950 to 351 BkWh in 1994-95, registering an average growth rate of about 10% per annum The details of gross generation and growth rates for different periods for thermal and hydro are given in Table 22 and Table 23.

Table 22. Gross electricity generation (BkWh)

	Hydro	%	Thermal (coal, diesel, gas)	%	Nuclear	%	Total generation
1950-51	2 5	49	2.6	51		-	5 10
1960-61	7 8	46	9 1	54		-	16 90
1970-71	25.2	45	28.2	51	2.4	4	55 80
1980-81	46.5	42	61.3	55	3.0	3	110 80
1990-91	71 7	27	186.5	71	6 1	2	264 30
1994-95	82.5	24	262 9	75	5 6	2	351 00

Source Economic Survey 1995-96

Graph 3 Capacity & generation of electric power (1950-95)

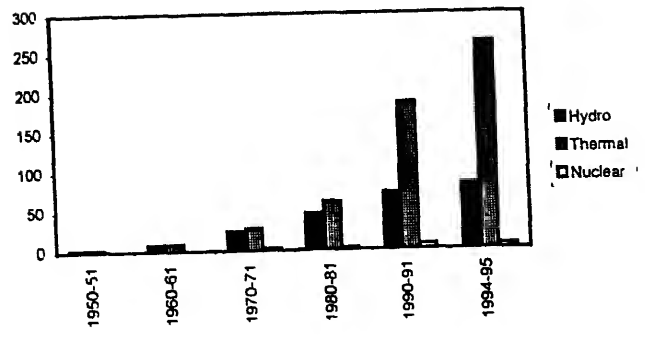


Table 23. Annual rate of growth of gross generation (%)

Period	Thermal	Hydro	Total
1950/51-1960/61	13.4	12 0	12 7
1960/61-1970/71	12 9	12 4	12 7
1970/71-1980/81	7 7	6 3	7 2
1980/81-1990/91	11 6	4 4	9 1
1950/51-1994/95	11 2	8 0	10 1

Source: CMIE, 1991

The average plant load factor (PLF) of thermal power stations is less than 60% However, the performance of 500 MW and 200 MW units have been satisfactory and their plant load factor (PLF) is higher than the national average The small capacity plants mainly due to their age and poor maintenance have low PLF and their performance can be improved only through life extension studies and rehabilitation programs There are many reasons for poor operations of the power plants. These include inadequate attention to planned maintenance and the poor quality of coal supplies The quality of coal has been declining steadily over the years The average gross calorific value of coal supplies to power plants has declined from 4,600 kCal/kg in 1975-76 to about 4,000 kCal/kg in 1994-95. This results in high specific coal consumption, lower availability of coal mills, high specific oil consumption, poor performance of ESPs, etc

Renewable energy sources

The contribution of renewable energy sources to total energy supplies/consumption is very small, but may increase in the future. The existing installed capacity of some of the renewable energy sources is given in Table 24.

Table 24. Installed capacity of RET sources

	Installed capacity
Wind energy	500 MW
Mini-micro hydel	400 MW
Biomass gassifiers	100 MW
Cogeneration	400 MW
PV water pumps	765 Nos.
Wind pumps	3017 Nos.

Coal movement

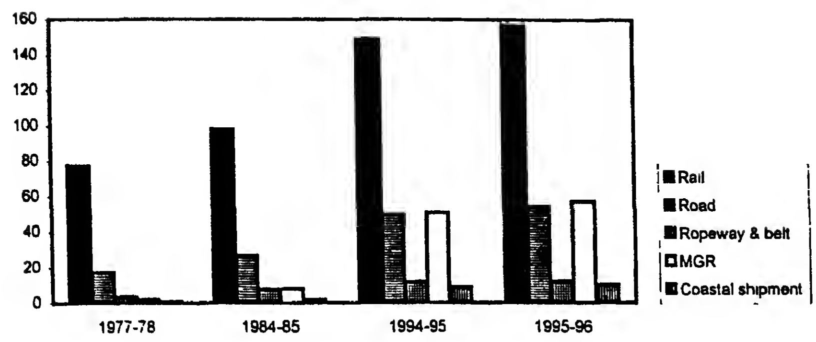
Coal dispatches from pit-heads are through various modes. Rail and road modes constitute the most important means of coal dispatches from the pit-head In recent years the MGR system of coal movement has made rapid strides and in 1994-95 its share was 21% in the total movement, which was more than the coal moved by road. In the future, the quantity to be moved by the MGR system would continue to grow and would remain second largest mode after rail. The mode-wise coal dispatches for a few selected years and the percentage share of each mode in the total dispatches are given in Table 25

Table 25. Mode-wise coal dispatches (Mt)

Year	Rail		Road		Ropeway and Belt		MGR		Total		Coastal shipment
	Mt	%	Mt	%	Mt	%	Mt	%	Mt	%	Mt
1977-78	77 5	78	17 3	17	3 6	3	2 0	2	100 3	100	0 7
1984-85	98 0	70	27 0	19	8 0	5	8 0	6	141 0	100	1 9
1994-95	148 9	57	49 8	19	11 9	4	50 8	20	261 4	100	9 0
1995-96	156 6	56	54 5	19	12 3	4	57 1	21	280 5	100	10 4

Source: Ministry of Coal

Graph 4 Inter modal split



An analysis of the above table shows the following:

- While coal production during the 10 year period (1984-85 to 1994-95) increased by an annual average of 5.6%, tonnage lifted by rail increased by only 3.8% The share of rail in the total coal movement has declined from 70% in 1984-85 to 56% in 1995-96.
- The quantity of coal moved by road has been increasing at an average annual rate of 5.8% during the last decade and has maintained its share at 19% in the total coal movement
- The coal moved by ropeway and belt increased marginally from 8 Mt to 12.3 Mt, but the share of these modes together has remained constant at less than 5%.
- The MGR system for transportation of coal has been introduced in the early 1980s for supply of coal to thermal power plants at pit-head [TPS owned by National Thermal Power Corporation (NTPC)] The system operates with dedicated rolling stock and rail systems Two power plants owned by SEBs also use privately owned wagons on their captive rail network to carry coal from pit-heads. The coal carried by this mode registered a 6-fold increase from 8 0 Mt in 1984-85 to 57 Mt in 1995-96 and its share has increased from 6% to 21% in the total movement.

The coastal shipment of coal started with linkages to Tuticorin power station from Raniganj coalfield The coal used to be moved by ships from Calcutta port, but now it is moving from Haldia port. The coal handling ports are Haldia, Paradip, Vishakapatnam, Madras and Tuticorin The coastal movement has been increasing consistently over the years with increasing demand from coastal power stations In 1995-96 more than 10 million tonnes have moved by this route compared to about 9 million in 1994-95

CHAPTER 4

Trends in energy consumption

Availability of commercial energy

The growth in consumption of energy is a function of the growth of the economy and energy consumption in India is constrained by supply shortages. Biomass energy is still estimated to contribute nearly 40% of the total energy consumed in the country. Biomass energy includes fuel wood. dung cakes and agricultural wastes.

The indigenous production of commercial energy in India has increased from a level of 53 Mtoe in 1972-73 to about 183 Mtoe in 1994-95, registering an average annual growth rate of 5.8% The details of indigenous production and imports for the different sources of energy are given in Table 26.

Table 26. Availability of primary sources of energy (Mtoe)

		1972-73	1975-76	1980-81	1990-91	1991-92	1994-95
Coal	Production	41 60	53 70	55 90	75 60	112 40	126 4
	Net imports	0 25	0 23	0 68	0 89	2 90	4 1
Crude oil	Production	7 30	8 40	10 50	30 20	30 30	32 2
	Net imports	12 10	13 60	16 20	14 60	24 00	27 4
Natural gas	Production	1 30	2 00	2 00	6 90	16 00	16 6
	Net imports	-	-	-	-	-	-
Hydro power	Production	2 30	2 80	3 90	4 30	6 10	7 0
	Net imports	-	-	-	-	-	-
Nuclear power	Production	0 09	0 22	0 25	0 42	0 50	0 5
	Net imports	-	-	-	-	-	-
TOTAL	Production	52 70	67 30	72 60	117 50	165 30	182 7
	Net imports	15 10	15 40	24 40	17 40	33 60	31 5

Source: TEDDY 1990/91, 1994/95

While coal accounted for as much as 62% of the total energy available in 1972-73, its share has marginally declined to 61% in 1994-95 The share of oil and natural gas has also remained at about 35% mainly through increased imports of crude oil and petroleum products

The commercial energy balance for 1994-95 and 1984-85 is given in Table 27 and Table 28 It can be seen from the table that the industrial sector continues to be the single largest consumer of commercial energy although its share is declining gradually. The energy consumption intensity in the industrial sector has also declined due largely to the relatively

rapid expansion of non-energy intensive industries. Improved technology and energy conservation measures may also be contributing to lower energy intensity. The energy intensity of transport has increased significantly over the years.

Table 27. Commercial energy balance for 1994-95 (Mtoe)

	Coal	Oil	Natural gas	Hydro	Nuclear	Total petroleum products	Total power	Total energy
A. supply								
Inflow								
Production	126 4	32 2	16 6	7 0	0 5		7 4	182 6
Imports	4 1	27 4	-	-	-	14 3	-	45 7
TOTAL	130 4	59 6	16 6	7 0	0 5	14 3	7 4	228 3
Outflow								
Exports	0 1	-	-	-	-	3 4	-	3 5
Stock changes	-1 6	3 1	-	-	-	0 2	-	1 7
TOTAL	-1 5	3 1	-	-	-	3 6	-	-
B Availability (inflow-outflow)	132 0	56 5	16 6	-	-	10 7	-	223 2
C. Conversion								
Soft coke	0 2	-	-	-	-	-	-	0 0
Pet refining	-	56 5	-	-	-	54 6	-	1 9
LPG extraction	-	-	1 6	-	-	1 6	-	-
Power generation	77 6	-	5 4	7 0	0 5	2 6	93 1	93 1
Conversion losses	51 8	-	3 9	4 6	0 3	1 7	62 3	62 3
Auxiliary consumption	2 6	-	0 0	0 0	0 0	0 1	2 7	2 7
TOTAL	54 3	-	3 9	4 7	0 3	1 8	65 0	65 0
Transmission & distribution	-	-	-	-	-	-	5 9	5 9
Flaring of natural gas, etc	-	-	1 7	-	-	-	-	1 7
Total conversion	77 8	56 5	8 8	-	-	53 7	70 9	74 5
D Net availability (availability-conversion)	54 2	-	7 8	-	-	64 3	22 2	148 6
E Consumption	54 2	-	7 8	-	-	64 3	22 2	148 6
Agriculture		-	0 1	-	-	0 9	6 7	7 7
Industry	53 9	-	1 5	-	-	10 0	8 5	73 9
Transport	0 3	-		-	-	32 6	0 5	33 4
Residential		-	0 2	-	-	11 1	4 0	15 4
Other uses		-		-	-	2 1	2 5	4 6
Non-energy uses		-	6 0	-	-	7 6	0 0	13 6
TOTAL	54 2	-	7 8	-	-	64 3	22 2	148 6

Source: TEDDY 1996

Table 28. Commercıal energy balance for 1984-85 (Mtoe)

	Coal	Oıl	Natural gas	Hydro	Nuclear	Total petroleum products	Total power	Total energy
A supply								
Inflow								
Productıon	72 3	29 0	6 2	4 5	0 3	-	4 9	112 4
Imports	0 3	13 6	-	-	-	6 3	-	20 3
TOTAL	72 6	42 6	6 2	4 5	0 3	6 3	4 9	132 6
Outflow								
Exports	0 1	-	-	-	-	1 0	-	1 0
Stock changes	3 2	7 1	-	-	-	-0 1	-	10 1
TOTAL	3 2	7 1	-	-	-	0 9	-	11 1
B Avaılabılıty (ınflow-outflow)	69 4	35 6	6 2	-	-	5 5	-	121 5
C Conversıon								
Soft coke	1 0	-	-	-	-	-	-	0 0
Pet refınıng	-	35 6	-	-	-	34 2	-	1 4
LPG extractıon	-	-	0 3	-	-	0 3	-	-
Power generatıon	31 9	-	1 6	4 5	0 3	2 8	41 2	41 2
Conversıon losses	21 3	-	1 2	3 0	0 2	1 9	27 6	27 6
Auxılıary consumptıon	1 1	-	0 0	0 0	0 0	0 1	1 2	1 2
TOTAL	22 3	-	1 2	3 0	0 2	2 0	28 7	28 7
Transmıssıon & dıstrıbutıon	-	-	-	-	-	-	2 9	2 9
Flarıng of natural gas, etc	-	-	2 7	-	-	-	-	2 7
Total conversıon	32 9	35 6	4 6	-	-	31 7	31 6	35 7
D Net avaılabılıty (avaılabılıty-conversıon)	36 5	-	1 6	-	-	37 1	9 6	85 8
E Consumptıon	36 5	-	1 6	-	-	37 1	9 6	85 8
Agrıculture	-	-	0 1	-	-	0 3	1 8	2 1
Industry	32 8	-	0 2	-	-	7 4	5 3	45 7
Transport	3 7	-	-	-	-	16 4	0 2	20 3
Resıdentıal	-	-	0 0	-	-	6 2	1 3	8 1
Other uses	-	-	-	-	-	1 1	1 0	2 5
Non-energy uses	-	-	1 3	-	-	5 8	0 0	7 1
TOTAL	36 5	-	1 6	-	-	37 1	9 6	85 8

Source: TEDDY 1996

Pattern of electricity consumption

Industrial sector is, by far the largest consumer of coal wıth 99.44 % of all the coal consumed ın India. A very small amount of coal was beıng consumed by the transport sector which has now been stopped wıth the phasıng out of the steam traction The consumption of coal in the domestic sector again ıs ınsignıficant Most of the coal ıs consumed by the power sector In the industrial sector, other maȷor consumers of coal are steel, cement and brick. Agrıculture and transport sectors are large consumers of electricıty and petroleum products and cannot use coal. Coal as a fuel, cannot be a substitute for these sectors

Table 29a. Sectoral Commercial energy consumption for 1994-95 (Mtoe)

Consumption	Coal	Natural gas	Petroleum products	Power	Total energy
Agriculture	-	0 1	0 9	6 7	7 7
Industry	53 9	1 5	10.0	8.5	73 9
Transport	0 3	-	32 6	0 5	33.4
Residential	-	0.2	11.1	4 0	15.4
Other uses	-	-	2 1	2 5	4 6
Non-energy uses	-	6 0	7 6	0 0	13 6
Total	54.2	7.8	64 3	22.2	148.6

Source: TEDDY 1996

There has been significant change in the pattern of electrical energy consumption in the different sectors. While during the period 1950s to 1970s, the largest consumer of electrical energy was industry, consuming more than 62 % of the total, agricultural consumption was less than 4%. With the growth of agricultural production in India due to increase in pump sets, the consumption of electricity in this sector has increased many folds in the last four decades and in 1993-94, it was almost 30%. The industry's' share has fallen from 62% in 1950-51 to about 40% in 1993-94. Domestic and commercial sectors taken together, the consumption has hovered around 20 to 25 %. Individually, the domestic sector consumption has increased by about 5.6 % while that of commercial sector has fallen marginally. The details are given in Table 29b.

Table 29b. Sectoral consumption trend - electricity (%)

	Domestic	Commercial	Industry	Traction	Agriculture	Others
1950-51	12 60	7 50	62.60	7.40	3 90	6.00
1960-61	10.70	6.10	69.40	3 30	6.00	4 50
1970-71	8.80	5 90	67 60	3 20	10 20	4.30
1980-81	11.20	5 70	58 40	2 70	17 60	4.40
1990-91	16 80	5 90	44.20	2 20	26 40	4.50
1991-92	17 30	5 80	42 00	2.20	28 20	4.50
1992-93	18 00	5 70	40 90	2.30	28.70	4.40
1993-94	18.20	5.90	39.60	2 30	29.70	4 30

Source: Economic Survey, 1996

Coal consumption trend

The coal consumption has increased from about 72 Mt in 1970-71 to 260 Mt in 1994-95. Electricity sector is the single largest consumer of coal followed by iron and steel and cement sectors The indigenous coal production is by and large meeting the country's demand except for the steel sector. The demand of washed coking coal for the steel plants in recent years is far outstripping the indigenous supply both in terms of quality and quantity. The existing washeries are old and are unable to meet the demand in terms of quality of supplies (< 17.5% ash content in coal) Therefore, 9 Mt of low ash coking coal is being imported annually by the steel plants for meeting their demand. Cement has emerged as the third largest coal consuming sector after power and iron and steel and consumed more than 11 Mt in 1994-95. The coal consumption by all other industries was slightly less than 10% of the total coal consumption. Railways who were the largest consumer till early 1970's have adopted the policy to phase out the steam locomotives by 2000 AD and thus the consumption has come to a level of only 0.65 Mt in 1994-95 The details of coal consumption by the major sectors are given in Table 30.

Table 30. Sectoral consumption trend - coal (Mt)

Sector	1960-61	1970-71	1980-81	1990-91	1994-95
1. Steel & Coke Ovens	9 1	13 5	22 4	27 6	33.4
2 Power(U)	**9.1**	**13.2**	**36.7**	**116.7**	**166.7**
3 Power (C)	#	#	#	12.5	14.5
4 Cement	2.3	3 5	4 8	9 7	11.2
5 Fertilizer	#	#	2 3	3 9	4.3
6 Railways	15 5	15 6	11 9	5 2	0.7
7 Soft Coke	2 6	4 1	1 3	1 3	0 5
8 Others	14 6	21 8	30 3	30 7	28 8
TOTAL	53 2	71 7	109 7	207.6	260 1

 # accounted for in "others" category,

Source: Ministry of coal

CHAPTER 5

Energy demand and supply projections till 2011-12

Energy demand projections

With the rapid growth in commercial energy consumption and the increasing burden on scarce resources, the need for energy demand analysis and energy conservation has assumed considerable importance. There are several approaches to energy demand analysis. Many demand estimates are based on an extrapolation of the past trends. TERI had recently carried out an analysis of the energy demand projections till 2011-12. In this analysis, the growth prospects of other economic sectors like transport, agriculture, has largely been estimated on the basis of past trends. However, in the case of industry, use had been made of industry's own planned growth and government's projections wherever possible The results of two scenarios: business-as-usual scenario and energy conservation scenario are given in the following paragraphs

Business-as-usual (BAU)

In the BAU scenario, the present energy supply and use pattern was allowed to persist with some marginal changes. The demand of commercial energy for different terminal years of the plans as estimated by TERI study are given in Table 31.

Table 31. Fuel-wise energy demand for BAU scenario

Fuel	Unit	1991	1996	2001	2006	2011
Commercial						
Coal	Mt	229.00	300 0	386 6	494 0	628.0
Natural gas	BCM	14 40	26.3	36 6	43 8	61.5
Petro products	Mt	59.60	65.0	86 0	114.0	144.5
Primary electricity	TWh	78 20	127.3	166.2	213.0	235.5
Non-commercial						
Crop waste	Mt	100.00	110 0	121 0	129.0	145 0
Firewood	Mt	247.00	270 0	295 0	315.0	344 0
Dung-cake	Mt	107.00	119 0	130.0	139.0	156.0
Biogas	BCM	0 66	1.3	1 9	2.4	3 0

Source: TERI study (UNEP)

Energy conservation scenario

The Inter-Ministerial Working Group on energy conservation has estimated that there is a potential of 20%, 20% and 15% energy savings in coal-based, oil-based and electrical equipment respectively, in the existing system. This will be achieved by the installation of heat recovery systems, replacement of inefficient boilers, computerization of process control operations, adoption of cogeneration systems and use of energy efficient equipment and lighting in domestic and commercial sectors.

This scenario considers energy conservation measures as indicated above together with improvement in agricultural pump sets, reduction in transmission and distribution (T&D) losses over the BAU, etc. Since conservation measures generally take time to be implemented, these options have been considered from the Ninth Plan Whereas in the BAU scenario T&D losses had been assumed at 21%, 19%, 17% and 15% in respective terminal years (to be achieved by eliminating commercial losses), in this scenario, a further 2% reduction in T&D losses in successive terminal years excepting 2011 has been assumed. For the year 2011, a further 3% reduction has been assumed.

Under the energy conservation scenario, the savings in coal, petroleum products and natural gas has been worked out for the different terminal years of future plans and the resultant fuel-wise energy demand is given in Table 32.

Table 32. Fuel-wise energy demand under energy conservation scenario

Fuel	Unit	2001	2006	2011
Coal	Mt	352 6	438 0	554 0
Natural gas	BCM	36 6	43 8	58 5
Petro products	Mt	75 5	99 5	127 0
Primary electricity	TWh	166 2	213 0	235 5

Source: TERI study (UNEP)

Coal demand as assessed by Working Group on coal

The Planning Commission had carried out an analysis of the sectoral requirements of coal in the 8th Plan based on the proposed targets of consuming sectors. As per this analysis, the coal demand is about 300 Mt in 1996-97 (this has since been revised to 325 Mt) and 394 Mt in 2001-02. The Working Group for the 9th Plan constituted by the Ministry of Coal in November 1995 has assessed the coal demand for 9th Plan and beyond As per this report, the coal demand is estimated at 440 Mt in 2001-02 (as against 394 Mt assessed by the Planning Commission in the 8th Plan document) and 557 Mt in 2006-07 and 711 Mt in 2011-12 The Working Group has reduced the coal demand for electricity generation as assessed by the

CEA This reduction is based on assuming a lower level of specific coal consumption as compared to CEA's assumptions The sector-wise coal demand for all sectors as assessed by the Working Group is given in Table 33

Table 33. Sector-wise coal demand (as worked out by Working Group on coal and lignite)

Sector	1996-97	2001-02	2006-07	2011-12
Iron & steel	40 5	51.6	64.0	78 0
Power (utilities)	210 0	291.2	351 0	435 0
Cement	15.3	19.9	30 0	45.0
Others	59 2	77.0	112 0	153 0
Total	325 0	439.7	557.0	711.0

Source: Ministry of Coal

Summary of coal demand projections

To summarize, the total coal demand for the period 1996-97 to 2011-12, as worked out by different agencies are given in Table 34.

Table 34. Coal demand worked out by different agencies (Mt)

Total coal demand	1996-97	2001-02	2006-07	2011-12
Working Group's estimate	325	440	557	711
TERI's estimate				
- BAU scenario	300	387	494	628
- Energy conservation scenario	300	353	438	554

Electricity demand

CEA projections

Electricity demand has been growing at a much faster rate as compared to the demand for other fuels The demand for electricity has outstripped the projections especially in the agriculture and domestic sectors The country's additional needs during the 15 year period from 1996-97 to 2011-12 have been projected by the CEA at 1,75,000 MW bringing the total capacity in 2011-12 to 2,56,000 MW. This necessitates an average addition of 11,700 MW per annum for the next 15 years Table 35 gives the generation expansion plan as worked out by CEA. This plan is based on high hydro scenario in which the share of hydro increases from the existing level of 27% to about 34% This is very unlikely to occur and therefore

CEA's estimates have been revised by TERI in their energy demand exercise to a more likely generation expansion program.

Table 35. CEA's perspective plan 1992-2007 scenario - high hydro (MW)

Type of plant	Installed capacity			
	1991-92	1996-97	2001-02	2006-07
Hydro	19,508	28,905	46,601	71,144
Thermal	48,331	74,405	98,493	1,29,978
Nuclear	2,035	3,210	8,150	10,180
Total	69,874	1,06,520	1,53,244	2,11,302

Source: CEA

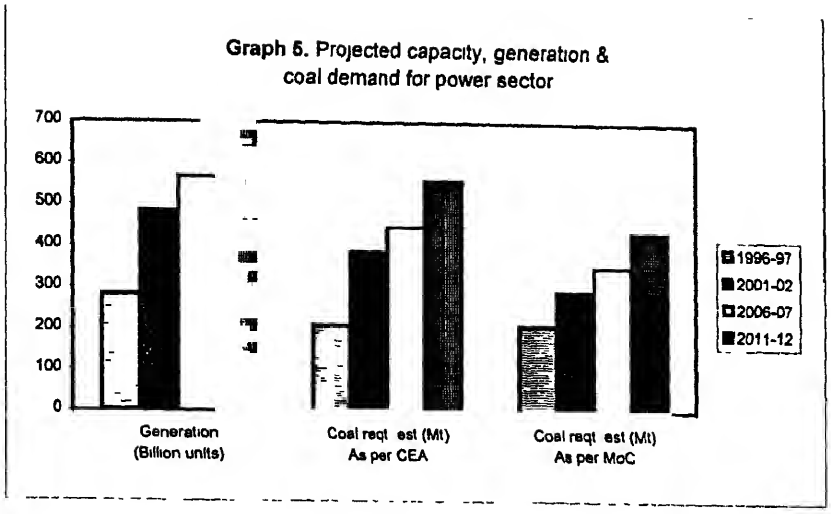
Coal demand for electricity generation

The coal demand for electricity generation as worked by CEA and MOC are provided in Table 36.

Table 36. Assessment of coal demand for electricity generation

Year	Capacity (MW)	Generation (Billion units)	Coal requirement estimate (Mt)	
			As per CEA	As per MOC
1996-97	50,013	282	210	210
2001-02	87,170	485	387	291
2006-07	1,16,400	566	447	351
2011-12	1,38,300	690	559	435

Source: CEA and MOC



TERI's projections

A linear programming model called ELGEM (Electricity Generation Expansion Model) jointly developed by the Canadian Energy Research Institute (CERI) and the Alberta Research Council (ARC), has been used In addition to conventional generation technologies such as coal, hydro, and nuclear for meeting demand, ELGEM allows for the examination of other options for meeting demand such as demand-side management (DSM) programs, renewable energy technologies, cogeneration, clean coal technologies, reduced T&D losses, etc.

The ELGEM model has assessed the electricity demand under various scenarios They are

- BAU
- Reference case
- DSM
- Clean coal technology
- Cogeneration
- Reduced T & D losses
- Optimistic scenario which is in-fact the reference case with all options such as DSM, CCT, Cogen and reduced T&D losses taken into consideration.

The results of different scenarios are given in **Annexure 1**. The results of optimistic case is presented in Table 37. The following points emerge from the results.

In the year 2011-12,

- Generation requirement from various energy sources to meet the demand of electricity is 234000 MW
- There is no shortfall and the demand is fully met
- Share of hydro electricity in total falls down from 27 % to 21 %
- 23,700 MW of generating capacity is proposed to be exploited through DSM, CCT, Cogeneration and decentralized power like small hydro, solar etc.
- Coal consumption is assessed at 406 million tonnes
- Oil and natural gas has low consumption

Table 37. Optimistic scenario - reference case with all options open

Year	1991	1996	2001	2006	2011
Installed generation (MW)					
Coal	45,509	43,716	59,631	86,217	1,33,500
Nuclear	1,785	2,814	4,831	10,751	16,704
Natural gas	2,587	4,968	19,889	20,489	20,866
Hydro	19,189	23,938	33,334	42,243	49,854
Other	0	0	1,900	6,272	13,294
Subtotal	69,070	75,436	1,19,586	1,65,974	2,34,218
% Hdyro (%)	27 8	31 7	27 9	25 5	21 3
Capacity shortfall	0	0	0	0	0
Total capacity required	69,070	75,436	1,19,586	1,65,974	2,34,218
Installed generation (MW)					
Decentralized power	0	500	1,240	1,500	4,400
Demand-side management	0	2,557	4,893	7,076	11,129
Cogeneration	0	0	1,900	6,272	13,294
Clean coal technologies	0	0	0	6,439	23,777
Energy resource consumption					
Coal ('000 t)	1,29,282	1,46,055	2,08,756	2,82,385	4,06,000
Natural gas (million m^3)	3,322	4,496	12,245	12,473	12,623
Fuel oil ('000 m^3)	911	1,030	1,547	2,040	2,702
Nuclear fuel ('000 kg U)	856	1,394	2,446	5,527	8,624

Source: ELITE, December 1994, CERI; ARC; and TERI

Given below (Table 38) is the summary statement of the coal demand for generation of electricity by CEA, MOC and TERI's estimates under different scenario through ELGEM model results.

Table 38. Coal demand for electricity generation (Mt)

	1996-97	2001-02	2006-07	2011-12
CEA estimate	210	387	447	559
Working Group's estimate	210	291	351	435
TERI's estimate				
■ BAU (Base case)	163	256	395	622
■ Reference case	169	246	320	406
■ Optimistic scenario	146	209	282	406

Energy supply

Domestic supply

TERI had carried out a study on the supply options and availability of different fuels for the terminal years of 9th and 10th plans. The following assumptions have been made, while assessing the supplies of different fuels. Due to low R-P ratio for crude oil and natural gas, the production is pegged at 2001-02 levels for future.

- Production of crude oil would reach a level of 47 Mt in 2001-02 and remain at the same level in 2006-07 and 2011-12.
- Production of natural gas would reach a level of 36 BCM in 2001-02 and remain at the same level in 2006-07 and 2011-12.
- Non-coking coal production will grow at an average annual rate of 6%
- Coking coal production is pegged at 60 Mt in 2001-02, and 70 Mt in 2006-07 and 2011-12 due to lower reserves of good quality coking coal.
- Marginal improvement in PLF of power plants.
- Reduction in T&D losses and improvement in the system load factor of the utility systems.

The results of the study are given in Table 39.

Table 39. Domestic availability of various fuels in the different terminal years

Fuels	Units	1991	1996	2001	2006	2011
Coal	Mt	229.00	290 0	367 0	474 0	608 0
Natural gas	BCM	14 40	26 3	36 6	36 6	36 6
Crude	Mt	30 30	35 0	47 0	47 0	47 0
LPG	Mt	2.65	2 5	3 2	3.9	4 9
SKO	Mt	8.38	6 6	8.0	9 9	11.7
Fuel oil	Mt	9.20	10 6	13.1	16 1	19 7
Naphtha	Mt	3 46	3 5	5 0	6 6	7 2
HSD	Mt	24 00	21 2	25 7	32 0	38 5
MS	Mt	3 57	4 3	5 3	6 6	8 0
ATF	Mt	1 56	3 2	2 6	3 3	4.0
Electricity	TWh	287 00	426 1	560 5	718.0	907 0

Energy demand-supply balance for BAU scenario

The demand-supply balance for the BAU scenario shows deficit in supplies for most fuels, which may have to be met through imports.

Import requirements for the various fuels as estimated by the model are presented in Table 40. The iron and steel sector has indicated that the import of coking coal would increase from 6-7 Mt in 1991 to 10 Mt in 1996-97, 19 Mt in 2001-02.

Table 40. Import requirements of various fuels under BAU scenario

Fuels	Units	1991	1996	2001	2006	2011
Crude	Mt	24 00	30.00	32 7	52 70	72 7
Natural gas	BCM	-	-	-	7 36	24 9
Coal	Mt	5 90	10 00	19 0	20 0	20 0
ATF	Mt	0 02	0 90	2 1	4 50	6 2
LPG	Mt	0 22	1 34	1 8	2 30	2 5
SKO	Mt	3 40	7 30	7.2	8.70	10 3
Fuel oil	Mt	-	0 40	1 4	-	-
HSD	Mt	5 30	4 20	4.6	6 20	5 3
MS	Mt	-	0 80	6.0	12 20	22 3

Energy supply-demand balance for energy conservation scenario

Under the energy conservation scenario, savings in coal, oil and natural gas have been estimated. The details are given in Table 41.

Table 41. Saving under conservation scenario

Fuel	2001-02		2006-07		2011-12	
	Demand	Available	Demand	Available	Demand	Available
Coal (Mt)	352.6	367.0	438.0	474.0	554.0	608.0
Crude (Mt)	75.5	47.0	99.5	47.0	127.0	47 0
Natural gas (BCM)	36.6	36 6	43.8	36 6	58.5	36 6

Coalfield-wise coal production / supply plan

It can be seen from Table 42 that the coal production / supply has to increase significantly from eight coalfields to meet the demand for coal in future. The increase ranges from a low of 6 % in Korba to a high of 80 % in North Karanpura.

Table 42. Coalfield-wise coal production projections (Mt)

Coalfield	2001-02	2006-07	2011-12
Raniganj	20 92	26 0	27 0
Mugma Salanpur	3 76	3 0	2 0
Rajmahal	13 02	**16.0**	**20.0**
Jharia	34 40	36 0	36 0
Giridih	0 30	0.5	0 5
West Bokaro	5 45	13 0	15.0
East Bokaro	8 12	16.0	22 0
Ramgarh	2 60	3 0	3 0
South Karanpura	5 05	11 0	12.5
North Karanpura	19 74	**26.0**	**47.0**
Singrauli	49 00	**58.0**	**67.0**
Wardha Valley	19.10	**22.5**	**23.6**
Umrer	2.40	0.8	-
Patherkhera	2 73	2 1	1 5
Pench-Kanhan	3 57	4 4	4.7
Central India	24.20	24 0	24.0
Korba	41.22	**63.0**	**67.0**
Ib valley	13.80	**43.0**	**60.0**
Talcher	29.20	**51.0**	**80.0**
North-East	1 00	2 0	2 0
Singareni	36.00	**39.0**	**42.5**
Others	43.00	7 0	7 5
TOTAL	346.00	473 0	572 0

Source Ministry of Coal

Competitiveness of coal with other fuels

Fuel substitution

Indigenous coal can be substituted by other fuels including imported coal in power sector, subject to the techno-economic feasibility. In cement industry, the imported coal can be a replacement to a limited extent in the southern belt, specially with low availability of appropriate quality indigenous coal and the waival of import duty against export of cement. The brick industry, though is trying to use other fuels in conjunction with coal, such as green wood, it will continue to be largely dependent on coal as the main source The possibility of fuel substitution is ruled out in the existing power plants in northern and central India because of the increased cost of inland transportation of imported fuel and in eastern India because of the proximity to the coalfields but the plants in south, both the existing and the new, clearly have wider options for choosing the fuel. While the existing plants in southern India can use imported coal as a sweetner to the maximum extent of about 30%, the new plants can be designed to use only imported coal. The option of using oil / NG /LNG is also open to these power plants. However, large volume imports are dependent on the port infrastructure, which will need large capital investment and time.

The steel industry is already using imported coal to a large extent and will continue to do so because of the shortage of right quality coking coal in India. Any substitution of coal in steel industry by other fuels is unlikely but natural gas can be gainfully utilized in the production of sponge iron. Thus, the demand for coal or otherwise will be dictated by the generating capacity and its mix in future.

As per the demand projections for coal, the three major coal consuming sectors, viz, electricity generation, steel and cement would require 90% of the total coal demand (power 70%, steel 15%, cement 5%) The steel industry would be importing 30% of its coal requirement, mainly due to non-availability of right quality low ash coking coal from domestic sources. This quantity can go up to 50% if indigenous availability is further restricted

Cement industry - coal demand

The cement industry also requires superior quality non-coking coal and its demand is projected at 45 Mt in 2011-12. It is a location specific industry being dependent on availability of cement grade limestone, which is concentrated in the states of Andhra Pradesh, Karnataka, Madhya Pradesh, Rajasthan, Gujarat and Tamil Nadu Supply of coal also gets restricted to a few coalfields and problems of quality of coal supplies exist The variation in quality of coal supplied to the cement plants from different sources at different times also seriously affects the operation of the cement plants. The problems are bound to increase

because of the limited potential of production of appropriate quality of coal from Singareni and Central India Coalfields, the logical and traditional sources of supplies This will compel the new cement plants to be linked to non-traditional coalfields mainly mining higher ash coal from open cast mines. The quality problem of supply from these coalfields can be tackled only by resorting to beneficiation of coal

The coal demand for cement sector has been projected at about 20 Mt in 2001-02. Assuming that 50 % of the coal demand would be met from conventional sources, the balance would have to be met from coalfields like Wardha, Korba, South Karanpura, Singrauli and Talcher in the form of washed coal from central washeries. Some cement plants have set up their own washing facilities.

Some cement plants located in the coastal states (Tamil Nadu, Gujarat) are already importing coal to meet their requirements. The Central Government has permitted cement exporting units, the benefit of importing coal duty free to meet their requirements. At present, about 1 5 Mt of coal is being imported by these units and this trend may continue and it is assessed that the import of coal for cement would increase to 3 Mt in 2001-02, 4 Mt in 2006-07 and 5 Mt in 2011-12.

Landed cost of coal supplies to cement units

For comparison of delivered cost of coal supplies of imported and indigenous coal, an exercise was carried out jointly with CMPDI in 1994 for a study sponsored by the Ministry of Industries, GOI.

The landed cost of imported coal and indigenous washed/ raw coal for destinations in Tamil Nadu and Gujarat have been worked out and are given in Table 43. For Tamil Nadu cement unit, washed coal is supplied from Talcher coalfields and for Gujarat unit, the raw coal supply is from Singrauli coalfield (Grade C).

Table 43. Comparison of indigenous raw / washed coal and imported coal

Parameters	Cement unit in Tamil Nadu		Cement unit in Gujarat
1. Imported coal custom duty free against cement export			
CIF cost $		50	50
CIF cost Rs ($ - Rs. 35)		1750	1750
Port handling charges		157	157
Transportation cost		336	55
Total landed cost of imported coal		2243	1962
2. Indigenous washed/ raw coal			
Type of coal	Washed	Washed	Raw
Source	Talcher	Talcher	Singrauli
Grade (60.40)	F	F	C
Distance (km)	1900	1900	1800
Cost of raw coal	336	336	649
Middling credit	Yes	No	
Process cost	300	300	
Cost of washed coal at 85% cap.	85%	70%	
	748	909	
Freight charge	1052	1052	1011
Total landed cost	1800	1960	1660

Electricity generation

To meet the large increases in the demand of coal for electricity generation, 8 coalfields have been identified for rapid expansion in production capacities. These are Rajmahal, North Karanpura, Singrauli, Wardha, Korba, Ib Valley, Talcher and Singareni coalfields. It has also been decided to set up a number of washeries in these coalfields to ensure supplies of washed coal to new power plants.

TERI has carried out a study in 1995 to assess the demand for washed coal in the country and also to compare the delivered cost of imported coal and washed coal for a power station in the southern region. Madras port was taken as a destination and the details of costs are given below

Imported coal price

Steam coal prices have been through a number of cycles over the 15 year period (1980-95): price rose sharply in the early 1980's, declined in the mid 1980's, rallied, declined again before raising in the late 1980's and before falling steadily to 1994. In 1995, there is a sharp turn-around in the prices following the out come of price negotiations for deliveries in 1995 - of the order of 20% for steam coal over 1994 prices As per information available the FOB price of steam coal in 1995 at Australian port was US $ 40 3/t and at South African port was US $ 32.9/t. The 1994 prices were US $ 34 35/t (Australia) and US $ 24 5/t (South Africa).

The average CIF price at Madras port is taken as US $ 50/t The imported coal would have an average gross calorific value of 6,500 kCal/kg The landed cost of imported coal per tonne at Madras port would be as follows:

CIF value	=	US $ 50
Import duty @ 20%	=	US $ 10
Sub total	=	US $ 60
Conversion (US $ 1 = Rs. 35/-)	=	Rs. 2,100
Port charges	=	Rs 157
Total	=	Rs. 2,257

Delivered price of indigenous raw coal at Madras port

The landed cost at Madras port is Rs 1014/ton and Rs.1,116/ton from Talcher and Ib respectively. Details are given in Table 38. It is assumed that the indigenous coal from Talcher and Ib valley coalfields would be 'F' grade with a gross calorific value of 3,600 kCal/kg The last column of the table below shows the cost of 1.8 tonne of indigenous coal of GCV = 3,600 which will replace one tonne of imported coal of GCV = 6,500.

Table 44. Landed cost of coal at Madras port (Rs per tonne)

Source	Route	Pit head price	Rail freight	Loading Port	Ocean freight	Unloading port	Total	CV equival.
Talcher	PDP_MAS	336	132	229	160	157	1014	1825
Ib Valley	PDP_VZA	336	303	173	147	157	1116	2008

Since, for every tonne of imported coal, 1.8 tonne of indigenous coal would be required for consumption, the delivered price of indigenous coal at Madras port would be Rs 1,825/ton for Talcher coal and Rs 2,008/ton for Ib valley coal Therefore, it can be concluded that with the present price of imported steam coal the indigenous coal is cheaper.

Table 45. Price of washed coal at pit-head (Rs./t) (process cost - Rs. 150/t)

	80% yield	70% yield
Raw coal cost ('F' grade 60% steam + 40% slack)	270	270
Royalty	50	50
Stowing duty	4	4
Sub total	324	324
Sales tax @ 4%	13	13
Raw coal cost at pit-head	336	336
Process cost per tonne of input	150	150
Cost of washed coal per tonne of input	486	486
Cost of washed coal per tonne of output	608	695
Selling price of washed coal (cost of WC + 10%)	669	764

Landed cost of washed coal at Madras port

Grade 'F' coal from Talcher is washed for which the process cost of washing is estimated at Rs. 150/t. The delivered price of washed coal from Talcher to Madras port is given in Table 46

Table 46. Delivered price of washed coal (Rs/t)

	80% yield	70% yield
Washed coal price at pit-head	669	764
Rail freight to Paradip	132	132
Loading port charges	229	229
Sea freight	160	160
Discharge port charges	157	157
Total	1347	1442
Price of 1 4 tonne of washed coal	1886	2019

Assuming that the washed coal would have a gross calorific value of 4,600 kCal/kg and GCV of imported coal to be 6,500 kCal/kg, 1 tonne of imported coal would replace approximately 1.4 tonnes of washed coal. As can be seen from the table, the washed coal price at Madras port would be cheaper than the imported coal

Competitiveness with natural gas

Natural gas

In the optimistic scenario for power generation (as given by the ELGEM model) the installed generation capacity based on natural gas increases from 2,587 MW in 1991 to 20,866 MW in 2011-12. The natural gas demand for this power generation capacity increases from 3 BCM in 1991 to 13 BCM in 2011-12. The quantity of natural gas required for power generation works out to about 30% of the projected indigenous availability of gas The natural gas indigenous availability in 2011-12 is projected at 37 BCM and to meet the total demand of natural gas (Table 34), 25 BCM will be imported. If imported natural gas is used for power generation, the landed cost of natural gas in Madras port ranges from Rs 550 to Rs. 800 per Gcal This is higher than the landed cost of indigenous raw coal, washed coal and imported coal at Madras port The landed cost of different fuels at Madras port are given in Table 47

Table 47. Cost comparison

Source	GCV (kCal/kg)	Landed cost per Giga Cal (10^9 cal) in Rs
Talcher raw coal	3,600	300
Talcher washed coal	4,600	304
Imported coal	6,500	
With 35% duty		384
With 20% duty		338
Natural gas	11,400	
US $ 16/GCal		544
US $ 20/GCal		680

There is a significant potential market for natural gas in the coastal states for industrial use (cement, steel, chemicals, etc.) and also for power generation. However, one of the most important factor for the potential to translate into actual utilization is the comparative cost. At present, the landed cost of imported LNG per Gigacalorie is higher compared to coal. If the cost becomes comparable, imported natural gas may be an option for meeting a part of the country's energy demand. Therefore, imports have been projected for 2006-07 and 2011-12.

The gas based power plants are cheaper to construct, have low gestation period, are easy to operate at much higher capacity levels, are more energy efficient, work on a higher PLF, can be started and stopped at short notice and thus have lower cost per unit of generation Similarly, the gas is a preferred fuel for industrial and commercial sectors due to its higher efficiency, no storage cost, higher output and better quality of product especially in

glass industry. However, the use of gas in these sectors, domestic included, has been restricted due to limited availability.

All allocation of natural gas to consumers are made by an inter-ministerial Gas Linkage Committee. This committee also decides the reallocation in situations of temporary shortages in production and supply. There has been no significant allocations since 1990, as allocations were made to prospective consumers, based on optimistic estimates of the availability of natural gas for the 15-20 years which did not materialize and there is no indication of its materialization in future. To bridge the demand supply gap, national and international private companies have been awarded gas fields but the availability from these will be materializing only after 9-10 years as none of them have acquired large properties needed for exploration.

Table 48. Projected availability of natural gas in MMSCMD

	1996/97	1999-00	2004-05	2006-07
Within Country				
Indigenous gas	64	72	72	72
CBM*	0	0	12	14
Total	64	72	84	86
Imports				
Through pipeline #				
Oman	0	0	28	56
Iran	0	0	0	25
As LNG	0	2	10	20
Total availability	64	74	122	187
Demand	88	147	187	188
Deficit	24	73	65	1
Deficit now estimated	24	73	105	96

Source: Ministry of Petroleum and Natural Gas

The probability of imports through pipeline has become remote due to various political, technical and commercial reasons and thus the deficits will increase to that extent The progress of award of lease to private companies for exploration of CBM has been tardy and as a result, till date, no one is exploring it. Even if things start looking up on this front, possibility of CBM being available for use by 2004-05 seems remote as the number of holes to be drilled is very large and time consuming. The total availability, thus is from the indigenous sources pegged at 72 MMSCMD only. Additionally, some LNG may be available by 2005-06 if the terminals come in place Looking at this current deficit of more than 100 MMSCMD, possibility of more indigenous natural gas going to power generation looks remote Thus, assuming that no further indigenous natural gas or CBM will be available for power generation, the only possibility is that of imported LNG and naphtha - imported and indigenous.

During early 90's, Planning Commission took a conscious decision for use of natural gas in Fertiliser sector as power sector could use coal, which was otherwise available in abundance Only 30 % of the total gas production was allocated to power sector for the gas turbines in different states. The possibility of more gas being available, as stated earlier, is ruled out.

Table 49. Demand for natural gas in MMSCMD

State	Fertz	Power	Sponge Iron	Glass	Others	Total
AP	10	3	5	5		23
Delhi				1	2	3
Gujrat	12	12	1	16	5	46
Haryana	1	1		2	3	7
Karnataka			2	3	4	9
MP	3	4	5	3	6	21
Maharashtra	11	13	2	16	5	47
Orissa		0			1	1
Rajasthan	2	6	1	2	5	16
TN	3	2	2	2	4	13
Tripura					2	2
UP	4	14	7	4	2	31
South(Misc)	9	13	4	8	4	38
East(Misc)	1	2	1		1	5
TOTAL MMSCMD	56	70	30	62	44	262
TOTAL BCM	21	26	11	23	16	96

Source: GAIL 20/5/96 150 MMSCMD = 55 BCM/year

Table 50. Long Term Demand for NG

	1999-00	2004-05	2009-10	2019-20
Northern				
Power	17.6	28.85	42 85	87 55
Fertz	17 18	17 18	17 18	17 18
Sponge Iron	2	4	5	7 2
Industry	9.6	10 35	11 4	13 4
Domestic	0.5	1 33	2	2.66
Internal Use/ Shrinkage	2 6	3.1	3.96	5 5
Total	49 48	64 81	82.39	133.49
Western				
Power	18.2	26.1	55.8	140 64
Fertz	9.19	9 19	9.19	9 19
Sponge Iron	3 94	4	5	7 2
Industry	31.72	34 21	36.85	44 3
Domestic	1 11	1.33	2	2 66
Internal Use/ Shrinkage	3	3 3	4 36	5 83
Total	67 16	78.13	113 2	209.82
Southern				
Power	7 63	17 06	57 41	161 25
Fertz	3 52	3.52	3.52	3.52
Sponge Iron	1 5	4	5	7.2
Industry	16 25	17.53	18.88	22 7
Domestic	0 5	1 5	1.5	3
Internal Use/ Shrinkage	0 5	1 33	2	2 66
Total	29.9	44 94	88.31	200 33
Grand Total	**146.54**	**187.88**	**283.9**	**543.64**

Source: Planning Commission 20/5/96

Import of LNG

The middle east countries have large reserves of gas, almost one third of the worlds reserves, leading among them are Iran, Qatar, Saudi Arabia etc. Other country in the region are Indonesia, Myanmar and Malaysia. Many of these countries are expanding existing capacities and creating new grassroots LNG capacities. These are some potential sources for import of LNG for east and west coasts and the cost of such import may vary between US$ 3 5 to 5 per MMBTU.

Cost of thermal power generation from all fuels

A recent study (1996) conducted by TERI shows that on an average, in Southern India on east and west coast, the unit cost of power generation for different fuels is shown in Table 51. These costs are for a location at the coast and will be higher if the fuels are transported inland.

Table 51 Cost of power generation using different fuels

Fuel option	Rs per kWh
Imported LNG	2 23
Imported Coal	2 20
Indigenous Naphtha	2.01
Indigenous Coal	1.98
Imported Naphtha	1 93
Indigenous Natural Gas	1 68

Source. TERI Shell study

Indian coal can remain the only source of power generation all over the country only when the power cost per unit of generation from other fuel sources are higher An analysis shows that the indigenous coal can be very competitive within a distance of about 800 km from the production source. For a 500 MW unit, situated within 800 km and using grade E coal can produce an unit at about Rs 2.23. Beyond this distance, all other fuels will compete with coal depending on their availability Infrastructure may become a problem in these cases Natural gas is by far the cheapest due to its administered price Imported and indigenous naphtha also compete with Indian coal

CHAPTER 6

Environmental, capital and infrastructure considerations

Introduction

The production plans for coal are based on the major assumptions that

- the coal industry would be able to meet the total demand for non-coking coal from the power and industry sectors and
- the demand of the steel sector would be partially met by import of low-ash prime coking coal to the extent of 30-40% of the demand.

Historically, coal production plans have been drawn up to match demand. However, with the reduction in import duty on non-coking coal from 85-20%, it is expected that some industrial consumers in the southern and western coastal regions may import superior grade non-coking coal. In addition, some cement plants in these areas which export cement would import non-coking coal at zero duty to meet their coal requirements. Also, the new power plants coming up in the private sector in these areas have the option to import non-coking coal for their consumption

The three major issues which would have a direct impact on the domestic coal production/availability are (i) environmental impacts due to mining operations, (ii) infrastructural constraints for coal movement and (iii) capital resources for investment. These are discussed in the following paragraphs

Environmental issues in coal mining

The magnitude and significance of environmental degradation due to coal mining depends on the method of mining and beneficiation, scale and concentration of mining activity, geological and geo-morphological setting of the area, nature of deposits, land use pattern before the commencement of mining operations, and the natural resources existing in the area Opencast mining operations pollute the environment much more severely than does underground mining.

Land

The most serious import of mining operations is on land use pattern in the area. Earlier, most of the coal mines in India were underground mines and generally restricted to Jharia and Raniganj coalfields. However, after nationalization, coal production has been increasing

rapidly and in the last two decades, the incremental production has come from opencast mining. This emphasis on opencast mines has led to degradation of land and displacement of population. Due to high density of population, acquiring large tracts of land required for opencast mining is difficult and the issue of resettlement and rehabilitation of people gains immense significance. The present rehabilitation package to resettle the displaced persons has not received a favourable response from the land oustees.

The extent of inheritance of land by CIL at the time of nationalization was about 42,000 ha. Since nationalization, about 56,000 ha of land has been acquired for mining and non-mining activities brining the total to about 1,00,000 ha of land under coal mining occupation. An additional 79,000 ha of land (as on 1993) is pending for acquisition. The company-wise details are given in Table 52. It is also reported that about 20,000 families have been displaced since nationalisation of mines out of which, employment has been provided to 18,700 families. However, the number of landless families affected due to mining activity is not available.

Table 52. Area under mining activity (ha)

Company	Quantum of inherited land	Total area acquired (post nationalization)	Area pending for acquisition as in 1993
ECL	9,962	6,692	8,108
BCCL	11,481	1,959	2,877
CCL	13,137	16,919	30,413
WCL	2,966	9,714	10,714
SECL	2,043	7,220	8,933
MCL	-	2,885	17,017
NCL	1,429	10,215	69
NEC	1,365	-	845
Total	42,383	55,604	78,976

Loss of forest land

The impacts of mining on forest areas is of particular concern in India as there is considerable overlap between tropical forests and mineral reserves. Opencast mining destroys forest land totally. Forest land is, however, normally not released for external dumps and infrastructure facilities. While subsidence has some effect on forest land in underground mines, it is normally not acquired in underground mining areas. When forest land is released for mining the Government of India requires the company to undertake compensatory afforestation on non-forest land

Land degradation in coalfields

In old coalfields like Jharia, Raniganj and East Bokaro, the past unscientific mining operations have resulted in extensive damage to land and water resources in the area It is estimated that about 18,000 ha of land has been rendered derelict due to fires, subsidence, open excavation and waste dumps caused by mining operations The details are given in Table 53.

Table 53. Land degradation in mining areas (ha)

Area affected by	Raniganj	Jharia	Others	Total
Subsidence	5,094	3,497	526	9,117
Abandoned pits	-	1,268	3,632	4,900
External reject dumps	370	631	100	1,101
Fire	600	1,732	-	2,332
Total	6,064	7,128	4,258	17,450

In fact, in the Jharia coalfield, 22 fire projects were formulated and sanctioned by the Government for dealing with the fires at an estimated cost of about Rs. 200 crores. A sum of Rs. 72 crores has already been incurred so far and this has resulted in saving of about 100 Mt of coal reserves from burning An area of about 2,500 ha of land affected by fire has been reclaimed in the Jharia coalfield during the last decade. The fire projects are continuing and are in various stages of implementation.

Future requirement of land

The Planning Commission, Government of India, had carried out a detailed study on "Energy Modeling for India· Towards policy for commercial energy" (1989). For the coal sector the study had estimated the average norms for land requirement, and rehabilitation of coal projects based on the analysis of sample data of mines and projects These are given in Table 54 However, the norms would be different for different coalfields depending on geological parameters, capacity of mine and land-use pattern in the area, etc.

Table 54. Norms for land requirement and displaced population (ha/Mt capacity)

	Opencast mine	Underground mine
Norms for land requirement		
Land requirement/Mt of capacity (ha)	513 00	235
Share in total land of		
a Forest	0 31	
b. Non-forest	0 69	
Tenancy land per Mt of capacity	124 00	57
Forest land per Mt of capacity	159.00	73
Government land per Mt of capacity	230 00	105
Norms for rehabilitation of families		
Number of families affected/Mt of coal	173 00	32

Source: Planning Commission

Based on these norms and the future production plans, a rough estimate of additional land required and families likely to be displaced during the next 15 years has been estimated. The opencast mines will require about 1,30,000 ha of land and underground mines 20,000 ha of land. The total families likely to be affected on a very rough estimate is about 46,000 (44,000 for opencast mines and 2,000 for underground mines).

Rehabilitation policy

In order to provide effective rehabilitation and resettlement to the displaced population, the guidelines established by the World Bank include·

- adequate compensation for lost assets,
- assistance with relocation and support during the transition period, and
- assistance in re-establishing former living standards.

The guidelines further emphasize that the project design should minimize the need for involuntary re-settlement and that projects should ensure that those who have to move, benefit from the project that displaces them. The objective is to provide a means to improve their standard of living.

Keeping the above points in view, the Government has approved a rehabilitation package for displaced population vis-à-vis the coal industry. The package offers the following benefits to all displaced persons:

- plot of land (0.01-0.02 hectares) for each family in the rehabilitation colony,
- shifting allowance @ Rs. 1,000 -2,000 per family,
- lumpsum grant @ Rs 5,000 per family,
- economic compensation to land losers, who are not provided with employment, @ Rs 6,000 per annum (or Rs 500 per month) for 20 years,
- vocational training to one-third of the population affected @ Rs. 10,000 per family, and

- rehabilitation colonies with certain basic facilities such as primary school, dispensary, roads, etc.

In addition, the land losers are entitled to monetary compensation for the land acquired. Employment to one member of the family is given subject to job availability and suitability.

Land availability

The availability of land is the single biggest constraint for coal mining operations Land requirement for coal mining has two unique features.

- The requirement is very large as compared to other sectors
- The requirement is site-specific

The main problems of land acquisition faced by coal companies are as follows:

- There is enormous delay in processing the land acquisition proposals due to non-availability of up dated land records or the records of rights (ROR).
- Delay in processing of the proposal at the district and the subordinate levels and also at the state levels.
- Even for land for which acquisition processes have been completed, physical possession becomes difficult because of stiff resistance of the ex-land owners
- Non-availability of land for compensatory afforestation.
- Slow or no progress in the creation of the Land Bank by the State Governments for compensatory afforestation.
- Abnormal demand for employment, compensation and rehabilitation benefits by the land owners.
- Delay in transfer of Government land and high prices demanded by the State Government for such land.
- Due to large scale encroachment upon Government land proposed to be transferred to coal companies, transfer becomes difficult and delayed
- Different practices introduced by different State Governments for acquisition of land and absence of a uniform policy of action and methodology in this regard.
- Considerable enhancement of compensation amount and direction for other benefits including rehabilitation and employment through the intervention of Court of Law.
- Lack of uniform Rehabilitation Policy applicable to all coal bearing states

Technology options for coal production

The technology options (opencast or underground mining) is driven by geological, technical and commercial consideration. Opencast mining is almost always cheaper than underground mining. The coal extraction percentage is much higher in opencast mining (90%) as against 30-40% in underground bord and pillar mining, which is the most prevalent technology in Indian mines In addition, while thick seams are a definite advantage in opencast mines, they represent a serious challenge in underground mines. Many thick seams developed on bord and pillar method of mining are standing on pillars because of lack of proper technology to extract the pillars The other advantages of opencast mining include increased safety of operations and lower gestation period. The specific investment per tonne of coal is also comparatively lower than for underground mines.

Another major cause, which is in favour of opencast mining is that about 63% of the total coal reserves occur within 300 m depth and much of the reserves are in thick seams. The coalfield-wise break-up of the recoverable coal reserves (up to 300 m depth) amenable to opencast and underground mining together with the projected production in 2001-02 in percentage terms is given in Table 55.

Table 55. Coalfield-wise technology mix of coal reserves and production (%)

Coalfield	Recoverable reserves (down to 300 m)		Coal production (2001-02)	
	OC	UG	OC	UG
Raniganj	54 4	45.5	30 9	69.1
Rajmahal	79.8	20 2	100 0	-
Jharia	65 4	34.6	55 1	44 9
East Bokaro	78.0	22 0	87.7	12.3
West Bokaro	42 2	57 8	83.2	16.8
Ramgarh	91.8	8 2	100.0	-
South Karanpura	46 3	53 7	69.7	30.3
North Karanpura	85 4	14 6	94 9	5 1
Singrauli	64 0	36 0	100 0	-
Wardha	44 2	55.8	84 9	15.1
Kamptee	11 9	88 1	26 3	73 7
Pathakhera	-	100 0	-	100 0
Pench-Kanhan	5.6	94 4	2 5	97.5
Korba	64 2	35 8	93.5	6.5
Korea Rewa	22 4	77.6	28 7	71 3
Ib Valley	69 6	30 4	89 9	10 1
Talcher	77 1	22 9	98 1	1.9
Singareni	26 0	74 0	49 0	37 0

Source: GSI and Ministry of coal

From a study of the above table the following conclusions can be drawn .

- The entire coal production from Rajmahal, Ramgarh and Singrauli coalfields will be from opencast mining because, in the present pricing system, it will be uneconomical to exploit the coal reserves amenable to underground mining
- For similar reason, the share of opencast production in North Karanpura, Korba, Talcher and Ib Valley coalfields are higher than the share of coal reserves amenable to opencast mining.
- In East Bokaro and West Bokaro coalfields, the underground coal reserves cannot be exploited for technological reasons, before the bulk of the opencast coal reserves are exploited.
- In South Karanpura and Wardha coalfields, the adverse economics of underground mining and non-availability of suitable underground technology has resulted in higher share of opencast coal production However, this phase is only temporary and the opencast share in these coalfields may come down in future years
- In all other coalfields, the technology-wise mix of the coal production is not widely different from the technology-wise mix of the recoverable coal reserves.

Coal movement

Indian Railway is and will remain as the main mode of coal transportation in India. With the increase in dispatch of coal in unit trains of Box 'N' wagons, this commodity is being increasingly moved in the express goods fleet. Being the first charge on the IR, the coal trains travel by the shortest or fastest routes and other traffic gets routed on secondary routes One of the first studies to assess the adequacy of line capacity, and other infrastructure requirement for transportation of increased volume of coal traffic was carried out by RITES in 1988 This report identified the likely routes on which capacity constrains may get exposed. The actual coal flows in 1984-85 was taken as the baseline data and anticipated coal flows in future were worked out based on projected demand from consuming centers.

The RITES report also assessed the infrastructural requirements in rail network for a coal demand projections of 325 Mt in 1994-95 and 417 Mt in 1999-2000 However, the general flow of coal traffic and the demand centers (mostly power stations) also remains similar to the earlier projections. Keeping in view the current status of coal flows and the future demand projections, the recommendations of RITES report are valid even today except some increased traffic emerging from new sources such as Korba, IB, Talcher etc The IR has already implemented many of the recommendations on line capacity while others are in the process of being implemented.

Presently the share of railway in total movement of coal is about 56% and is likely to grow to 64 % by 2001-02 The share of rail transport as per different projections of demand and IR's projections are given in Table 56.

Table 56. Coal demand and share of rail transport (Mt)

	1996-97	2001-02	2006-07	2011-12
Working Group's demand estimate	325	440	557	711
Rail transport share	195	282	356	455
TERI's estimate				
BAU scenario	300	387	494	628
Rail transport share	180	248	316	402
Energy conservation scenario	300	353	438	554
Rail transport share	180	226	280	355
Railway's estimate	194	243	325	420

As against the demand projection of 325 in 1996-97 by WGC, the rail transport share @ 60% is about 195 Mt IR has projected 194 Mt as the coal traffic in 1996-97 in their annual plan However, as per TERI's demand projection, it is only 180 Mt

For year 2001-02, the projection by IR is 243 Mt which is adequate as per the projection of TERI at 226 Mt.

The projections for the years 2006-07 and 2011-12 are roughly estimated at 325 Mt and 420 Mt by the railways against TERI's projected requirement of rail transport needs of 280 and 355 Mt respectively

Inter-modal split for future coal movement up to 2001-02

Since power plants are the largest consumer of coal, the coal movement plans would depend mainly on the location of future power plants The pit-head power plants would draw coal through captive modes like MGR/own wagons, but the distant power plants would have to depend on rail and rail-cum-sea modes for coal movement. It is also assumed that road movement would not increase in the future from the levels of 1993-94, since they are costly, except for short lead destinations Rail however, would continue to remain as the most important mode and its share increases from 57% in 1993-94 to 64% in 2001-02. The projected mode-wise coal movement plans for 2001-02 is as follows.

Rail	235 Mt
Road	47 Mt
Ropeway/belt	12 Mt
MGR	75 Mt
Total	369 Mt

Future coal movement beyond 2001-02

Areas requiring special thrust are improvements in rail and port infrastructure to augment offtake from Korba, Ib Valley, Talcher and North Karanpura coalfields; augmentation of coal capacities in congested routes such as main line beyond Mughal Sarai, main line beyond Chkradharpur and East coast line beyond Cuttack, etc

Coastal movement

Coastal shipment has emerged as an important mode of coal movement It serves primarily to reduce rail leads after coal is initially carried from pit-head to linked ports Haldia, Paradip and Vishakapatnam ports are shipping coal for Tuticorin and other consumers in south. The details of coal handling ports are given in Table 57 Many of the ports are already handling cargo more than their designed capacities There are expansion plans for Paradip port to handle the increased volume of coal flows from Talcher coalfield. Since coastal movement has to increase for meeting the needs of consumers in the southern states, the coal handling capacities at Paradip and Vishakapatnam have to be substantially increased.

Table 57. Major ports capacity and traffic handled in 1993-94 (Mt)

Port	Capacity		Traffic handled	
	All commodity	Only coal	All commodity	Only coal
Calcutta	6.75	-	5 17	
Haldia	16.78	5.00	13.33	5.43
Paradip	7.65	NA	8 33	4.69
Vishakapatnam	23 35	NA	25 59	6.58
Madras	22 07	NA	26 54	5.87
Tuticorin	5.10	3 00	6 70	3.81
Cochin	10 66		7 62	
New Mangalore	9 55		8 63	
Mormugao	15 92		18 72	
Bombay	26.80		30 74	
Kandla	20 80		24 50	
JL Nehru	5.90		3 39	
Total	171 03	8 00	179 26	26 43

Source: Ministry of surface transport

Capital investment

An investment of Rs. 18,000 crores has been made in the coal sector during the 25 year period since nationalization of coal mines towards new projects, reorganization projects, existing mines and infrastructure facilities. The return on this investment has been poor due to various reasons including ineffective pricing system and low productivity of machine and men. The coal industry has always been dependent on the Governments budgetary support for its investments Government budgetary support for investment in the coal sector was as high as 98% of the total outlay till 1984-85 and in the 7th Plan was around 80%.

The approved 8th Plan outlay for the coal sector was Rs. 10,557 crores (in 1992 prices). The net budgetary support in the 8th Plan outlay has come down from a level of 31% in 1991-92 to 13% in 1994-95. Non-revision of coal prices has affected the internal resource position of the companies. The low levels of budgetary support together with low internal resource generation has affected 8th Plan projects and 9th Plan new starts. It is estimated that there will be a resource gap of about Rs. 5,500 crores for the development of projects during the 8th Plan.

The indigenous coal production is projected to increase from 270 Mt in 1995-96 to 608 Mt in 2011 An average investment of 6,000 crores (at 1996 price) is required every year for new capacity addition of approximately 20 Mt per annum and for maintaining existing production at reasonable levels

CHAPTER 7

Conclusions

Business-as-usual (BAU) scenario

The projected increase in the energy demand under the BAU scenario (TERI study) given in Table 31 (Chapter 5) are clearly unsustainable. Coal supply would have to be increased from the present levels of about 270 Mt (1995-96) to about 628 Mt in 2011-12 Coal's share in the total demand for energy remains at about 60% during this period (1995-96 to 2011-12) and hence maintains its position as the prime source of energy. In the indigenous energy supply scenario (Table 39) the share of coal increases from 61% in 1994-95 to 76% in 2011-12. Petroleum product consumption would be more than double in the same period The large increases in coal demand would place enormous pressures not only on the transportation infrastructure of the country, but also on the environment, both local and global. The projections of energy demand have been made on the basis of current consumption trends, which themselves reflect supply constrained demand and therefore, it is likely that actual consumption may be higher than the projections

Electricity generation capacity has to be increased from about 81,000 MW in 1994-95 to about 2,56,000 MW in 2011-12 (as per CEA's estimate) giving an average increase of 11,700 MW every year The share of natural gas in electricity generation would go up significantly but coal would continue to contribute nearly 70% of this capacity.

Energy conservation scenario

The projected increases in energy demand under the energy conservation scenario (TERI's study) given in Table 27 show a potential reduction of 57 Mtoe in 2011-12 as compared to the BAU scenario (Table 31) There is a savings of 74 Mt in coal demand, 20 Mt in petroleum products 3 BCM in natural gas. The measures include increased energy efficiencies, introduction of clean coal technologies, increased co-generation, reduction of T&D losses and demand-side management. In this scenario also, coal maintains its share in the total energy demand at about 60%.

Electricity generation capacity increases from 81,000 MW in 1994-95 to 2,34,000 MW in 2011-12 resulting in a saving of 22,000 MW. Natural gas consumption for power generation increases by 4 times in 2001-02 over the present levels After 2001-02 the availability of natural gas for power remains at the same level (about 33% of indigenous availability) in 2006-07 and 2001-02. The coal demand for power generation increase from 168 Mt in 1994-95 to 406 Mt in 2011-12 and its share in the total power generation is more

than 60%. Therefore, it can be concluded that coal will play the key role in electricity generation and in meeting the major share of energy demand in the country during the next 15 years (up to 2011-12).

Cost competitiveness of coal with other alternate fuels

The cost of indigenous raw coal and washed coal from some potential coalfields (Talcher, Ib Valley and Singrauli) have been compared with imported coal and imported natural gas. For comparison purposes, the delivered cost per tonne of these fuels at Madras port has been calculated For natural gas, the delivered cost per Giga calories has been worked out and compared with coal (imported and indigenous). The efficiency/ reduction in the cost due to use of imported coal (low ash) and natural gas (clean fuel) in industries or in power plant has not been considered. The results are given in Table 58 The results show that the indigenous coal (both raw and washed) in cheaper than imported coal and natural gas.

Table 58. Summary of comparison of cost of different fuels

Coal for Cement Plants	At TN cluster	At Gujrat cluster
Imported Coal custom duty free	2243	1962
Washed coal from Talcher		
with midl credit	1800	
without middl credit	1960	
Raw coal Gr C from Singrauli		1660
For Electricity Generation		
Imported Coal at Madras port	2257	
Raw coal at Madras port from Talcher	1825	
Raw coal at Vizag port from Ib	2008	
Washed coal at Madras from Talcher		
80 % yeild	1886	
70 % yeild	2019	

Constraints in meeting coal demand

The three major issues which would have a direct impact on the domestic coal production/availability are (i) environmental impacts due to mining operations, (ii) infrastructural constraints for coal movement and (iii) capital resources for investment. These are discussed in the following paragraphs.

The major impact of mining operations is on land and resultant displacement of population. Coal mining has already acquired about 1,00,000 ha of land till 1993 (including inheritance of land at the time of nationalization) and is projected that an additional 1,20,000 ha of land would be required in the next 15 years for capacity building to meet the increasing demand. This would displace about 56,000 families on the rough estimate.

Coal movement

Rail, road and MGR modes constitute the most important means of coal dispatches to various consumers but among them rail is and will remain as the main mode of transport of coal in the country. The share of rail in the total coal movement has declined from 78% in 1977-78 to 54% in 1995-96 and this reduction is mainly due to the pit-head power stations which take coal by MGR, which has increased from 2% to 21%. In the future, the share of coal movement is projected by railways at 64% by 2001-02. The coal quantities to be moved as projected by railways increase from 194 Mt in 1996-97 to 243 Mt in 2001-02 and 420 Mt in 2011-12. The railways are already implementing various plans to meet the coal movement projections for 2001-02. Beyond 2001-02, there will be constraints in coal movement from North Karanpura, Korba, Talcher and Ib Valley coalfields where production increases are very large (Table 36).

The coastal movement has been increasing consistently over the years with increasing demand from coastal power stations In 1995-96 more than 10 million tonnes have moved by this route compared to about 9 million in 1994-95. It is programmed to grow but is dependent on the extent of new capacity addition for coal transport to Paradeep, Vizag and handling at the ports

Capital investment

Till the end of the 7th Plan, the coal industry has been dependent almost fully on the governments budgetary support for its investments But in the 8th Plan, the government drastically reduced the budget support to just 13% in 1994-95 The coal industry has not been able to raise adequate internal resources due to various reasons including pricing, low productivity, surplus labour, etc This has affected 8th Plan projects and 9th Plan new starts It is estimated that there will be a resource gap of Rs. 5,500 crores for the development of projects during the 8th Plan

For increasing the domestic production from 270 Mt in 1995-96 to 608 Mt in 2011, it is estimated that about Rs 6,000 crores (at 1996 prices) would be required every year for new capacity additions of 20-30 Mt/annum. The raising of adequate resources is essential for meeting the demand

Annexure

Annexure 1. Extract from Planning for The Indian Power Sector - A joint study by Tata Energy Research Institute(TERI) and Canadian Energy Research Institute (CERI), June 1995

To assess the future demand of electrical energy and the consumption of different resources under different planning scenarios, a linear programming model called ELGEM (Electricity Generation Expansion Model) jointly developed by the Canadian Energy Research Institute (CERI) and the Alberta Research Council (ARC), has been modified to the Indian context.

In addition to conventional generation technologies such as coal, hydro, and nuclear for meeting demand, ELGEM allows for the examination of other options for meeting demand such as demand-side management (DSM) programs, renewable generation technologies, cogeneration, etc.

The questions which have been addressed include the following.

- What are the implications of various financial and resource utilization constraints on electric power development?
- How will new capacity additions required to meet forecast electricity demand in India affect the growth in emissions of particulates, CO_2, SO_2, NO_x, and nuclear waste?
- What is the extent of resources required to fully meet projected electricity demand, and what could be the extent of unrealized demand (or, alternatively, the capacity shortfall) under each constrained scenario?
- What impacts could DSM, CCTs, cogeneration and reduced transmission and distribution losses offer for meeting electricity demand in India and reducing environmental emissions?
- What are the cost implications of electricity supply, under various scenarios?
- What are the cost and emissions implications of an optimistic scenario that employs all available options in meeting India's electricity requirements?

Base case development scenario

Electric power sector in India has been expanding at a rapid pace over the last four decades. Serious concerns have been raised as to the ability of the Indian government to sustain this pace of development, and the physical ability of the electric power system to meet future demand for electricity services.

The Base Case represents a Business as Usual development strategy for the power sector. Other than limitations on expansion of hydro-electric generation capacity up to 80 GW; natural gas utilization restricted to a maximum of 14,700 million cubic meters (mcm) per annum; and new nuclear capacity restricted to an additional 27 GW by 2011; this is an unconstrained, least cost development scenario which meets all projected electricity demand.

The question being addressed is, "How large could the Indian electric power sector become, and with what configuration, if current practices were continued without constraints on development?"

A summary of the scenario results is provided in Table a From the 1991 level of 69 GW of capacity, the system expands over eight-fold to exceed 288 GW in 2011. While all energy requirements are met Coal-fired generation increases from 45 5 GW to over 214 GW, with coal consumption rising from 129 million tonnes (Mt) to over 622 Mt in 2011 Second to growth in coal-fired capacity is growth in gas-fired generation, which increases almost ten-fold, from 2.6 GW in 1991 to over 22 GW in 2011. Of the total hydro-electric potential of 80 GW, only 47 GW is developed by 2011, registering a 2 47 times increase over installed hydro-electric capacity in 1991. The share of hydro in the total installed capacity mix declines from 27 8 percent in 1991 to 16.3 percent in 2011, primarily due to cost considerations.

The average annual share of Indian gross domestic product (GDP) required to finance this massive expansion in generation capacity is close to 4 2 percent, reaching Rs 315,041 crores in 2011 This compared to an historical average annual investment of 3 2 percent of GDP in the electric sector.

The impact on emissions is considerable. Particulates increase over 1 4 times over the 1991 to 2011 period, and emissions of CO_2 increase close to five times their 1991 levels by 2011.

Table a. Base case (Business As Usual)

Year	1991	1996	2001	2006	2011
Installed Generation MW)					
Coal	45509	46478	81768	133626	214242
Nuclear	1785	2814	4831	4751	4704
Natural Gas	2587	13191	20355	21036	22249
Hydro	19189	26409	35827	41177	47086
Subtotal	69070	88893	142782	200590	288281
% Hydro	27 8%	29 7%	25 1%	20.5%	16.3%
Total Capacity Required	69070	88893	142782	200590	288281
Capital Investment	0	69370	191816	211667	315041
Energy Resource Consumption					
Hydro (MW)	9344	13452	18774	21146	22177
Coal ('000 tonnes)	129282	162902	256251	395251	622407
Natural Gas (millions m3)	3322	8818	12490	12761	13350
Fuel Oil ('000 m3)	911	1160	1962	3123	4991
Nuclear Fuel ('000 kg U)	856	1394	2293	1926	1625
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4943559	4671239	4847121	5843211
CO2 ('000 tonnes)	224793	292551	457930	693645	1078980
SO2 ('000 tonnes)	1230	1605	2532	3856	6023
NOx ('000 tonnes)	1193	1541	2413	3668	5721
Nuclear Waste ('000 m3)	9945	16189	26630	22363	18868

Reference case scenario

The development scenario described in the Base Case is clearly unrealistic for India. In particular, the financial investment required to underwrite the implied capacity expansion would necessitate an unprecedented diversion of national income to the power sector, assuming that the entire financial investment for power sector development were to be provided by the government

For purposes of comparison with alternative development scenarios, it was decided to generate a Reference Case scenario based on a realistic set of initial constraints for power sector development The structure of this scenario is the same as the Base Case, except:

- a financial constraint is imposed limiting capital investment in the power sector to historical levels of 3 2 percent of GDP forecast for India;
- a coal constraint is imposed limiting coal available for electric power generation to 406 Mt in 2011 and 650 MT in 2011. This constraint is imposed to capture both the physical capabilities of the mining and transportation network to provide coal volumes, and the declining quality of available coal; and
- renewable sources of electricity supply are assumed as part of the available generation mix.

The results of the Reference Case scenario (Table b) show that investment reaches Rs 264,560 crores in 2011, compared to Rs 315,041 crores under the Base Case, a reduction of 16 percent. Total installed capacity increases 3 25 times from 1991 levels to nearly 225 GW in 2011. Coal-fired generation expansion is constrained significantly relative to the Base Case, reaching 125 GW in 2011 compared to 214 GW in the Base Case The shortfall is partly made up by a significant expansion in nuclear generation, which increases ten times the 1991 level to total 18 GW in 2011, *versus* 4.7 GW in the Base Case

Capacity Shortfall, is the difference between the installed capacity required to meet the demand and actual installed capacity. This is a measure of the electricity demand which is not satisfied under this particular development scenario. The row labelled Total Capacity Required, therefore, represents the capacity which would be required under this scenario to meet projected demand for energy services. Total system capacity requirements reach 270.6 GW in 2011.

From a comparison of the difference between the Reference Case and Base Case scenario (Table c) the following points emerge:

- Shortfall capacity represents 16.9 percent of total capacity required in 2011. This is the major impact arising out of constraining coal and financial resources available.
- The share of hydro increases substantially to 26 percent in the Reference Case compared to 16 percent in the Base Case.
- Due to fuel constraints and limited resource availability, there is a substantial reduction in coal-based generation capacity, and an associated reduction in emissions.

All the scenarios discussed below are compared with the Reference Case. It is important to note that when the constrained upper bound for coal availability is reached, there will not be any significant difference in the total level of emissions. Hence, comparison of emissions per kWh is a more appropriate indicator.

Table b. Reference case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	54948	67327	91502	125421
Nuclear	1785	3214	6131	12051	18004
Natural Gas	2587	2485	20483	21010	22027
Hydro	19189	27168	35261	46860	59415
Subtotal	69070	87815	129203	171424	224868
% Hydro	27 8%	30 9%	27 3%	27 3%	26.4%
Capacity Shortfall	0	0	8565	18305	45745
% Gen Subtotal	0	0	6 6	10 7	20 3
Total Capacity Required	69070	87815	137769	189729	270613
Capital Investment	0	80000	147730	197700	264560
(Rupee Crores/Time Period)					
Installed Generation (MW)					
Decentralized Power	0	500	3200	4800	6400
Energy Resource Consumption					
Hydro (MW)	9344	13507	18405	25087	32373
Coal ('000 tonnes)	129282	168949	246024	320000	406000
Natural Gas (millions m3)	3322	3190	12558	13716	14700
Fuel Oil ('000 m3)	910	1236	1845	2479	3224
Nuclear Fuel ('000 kg U)	857	1387	3122	6203	9299
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4372912	5369262	5173031	4755311
CO2 ('000 tonnes)	224793	291619	440645	568188	715844
SO2 ('000 tonnes)	1230	1608	2435	3148	3975
NOx ('000 tonnes)	1193	1549	2322	2998	3781
Nuclear Waste ('000 m3)	9945	16104	36247	72015	107967

Table c. Reference case minus base case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	8470	-14440	-42123	-88820
Nuclear	0	400	1300	7300	13300
Natural Gas	0	-10706	128	-25	-221
Hydro	0	758	-566	5683	12329
Subtotal	0	-1077	-13578	-29166	-63413
Capacity Shortfall	0	0	8565	18305	45745
Total Capacity Required	0	-1077	-5013	-10860	-17668
Capital Investment	0	10629	-44086	-13967	-50481
(Rupee Crores/Time Period)					
Installed Generation (MW)					
Decentralized Power	0	500	3200	4800	6400
Energy Resource Consumption					
Hydro (MW)	0	55	-369	3941	10196
Coal ('000 tonnes)	0	6047	-10227	-75251	-216407
Natural Gas (millions m3)	0	-5628	68	955	1350
Fuel Oil ('000 m3)	-0	76	-116	-643	-1766
Nuclear Fuel ('000 kg U)	0	-7	828	4276	7673
Environmental Emissions					
Particulates ('000 tonnes)	0	-570647	698023	325910	-1087900
CO2 ('000 tonnes)	0	-932	-17285	-125457	-363136
SO2 ('000 tonnes)	-0	2	-97	-708	-2048
NOx ('000 tonnes)	-0	7	-91	-670	-1940
Nuclear Waste ('000 m3)	0	-85	9617	49652	89099

Demand-side management scenario

The DSM scenario makes available to the system a number of DSM options. The impact of the DSM options is greatest during the system peak, allowing the postponement of expensive peaking capacity in favor of more base load capacity The result is a better capability to meet projected system demand.

A summary of the DSM scenario results is provided in Table d, with differences from the reference case provided in Table e. Looking at aggregate system size, there is only a marginal difference in the two scenarios, but the DSM option lowers the capacity shortfall by 50 GW, reducing the total required capacity by 25 4 GW by 2011. DSM capacity reaches 11.13 GW in 2011. Capacity shortfalls relative to projected demand are eliminated until 2006, a significant improvement over the Reference Case. Installed capacity increases 2 9 times by 2011 relative to the 1991 level. It is important to note that DSM does not use capital from the financial constraint imposed on this scenario Since all resources are used to the limit, DSM reduces the shortfall. The emissions impact of DSM is felt most in the early projection periods. All emissions levels are reduced relative to the reference case, over the 1991-2006 period.

Table d. Demand side management scenario

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	48813	63085	94414	132085
Nuclear	1785	3214	6131	12051	18004
Natural Gas	2587	2485	19789	19946	22619
Hydro	19189	28191	37624	47645	60000
Subtotal	69070	82703	126629	174057	232709
% Hydro	27 8%	34 1%	29 7%	27 4%	25 8%
Capacity shortfall	0	0	0	577	12472
% Gen subtotal	0	0	0	0 3%	5 4%
Installed Generation (MW)					
Decentralised Power	0	500	2200	3750	6400
Demand Side Management	0	2089 2	4893	7250	11129
Energy Resource Consumption					
Hydro (MW)	9344	14089	19820	25306	32723
Coal ('000 tonnes)	129282	152045	210184	291816	406000
Natural Gas (millions m3)	3322	3190	12193	12628	14700
Fuel Oil ('000 m3)	911	1093	1567	2269	3219
Nuclear Fuel (000 kg U)	857	1523	3122	5785	9299
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4377781	4785887	4482879	4786761
CO2 ('000 tonnes)	224793	263007	379375	518439	715768
SO2 ('000 tonnes)	1230	1447	2090	2868	3975
NOx ('000 tonnes)	1193	1396	1995	2734	3781
Nuclear Waste ('000 m3)	9945	17679	36247	67161	107967

Table e. DSM scenario minus reference case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	-6135	-4242	2912	6664
Nuclear	0	0	0	0	0
Natural Gas	0	0	-694	-1064	592
Hydro	0	1022	2362	785	585
Subtotal	0	-5112	-2573	2633	7841
Capacity Shortfall	0	0	-8565	-17728	-33272
Total Capacity Required	0	-5112	-11139	-15095	-25430
Installed Generation (MW)					
Decentralized Power	0	0	-1000	-1050	0
Demand-side Management	0	2089	4893	7250	11129
Cogeneration	0	0	0	0	0
Clean Coal Technologies	0	0	0	0	0
Energy Resource Consumption					
Hydro (MW)	0	582	1415	219	350
Coal ('000 tonnes)	0	-16904	-35840	-28184	0
Natural Gas (millions m3)	0	0	-365	-1088	0
Fuel Oil ('000 m3)	0	-143	-277	-209	-5
Nuclear Fuel ('000 kg U)	0	136	0	-418	0
Environmental Emissions					
Particulates ('000 tonnes)	0	4869	-583375	-690152	31450
CO2 ('000 tonnes)	0	-28612	-61270	-49749	-76
SO2 ('000 tonnes)	0	-161	-344	-279	0
NOx ('000 tonnes)	0	-152	-326	-263	0
Nuclear Waste ('000 m3)	0	1575	0	-4854	0

Clean coal technologies scenario

From the list of CCTs , Integrated Gasification Combined Cycle (IGCC), Pressurized Fluidized Bed Combustion (PFBC), and Atmospheric Fluidized Bed Combustion (AFBC) were selected as candidate technologies, owing to their cost competitiveness and availability over the projection period and their potential for meeting emission control requirements. As shown in Table f and Table g, the CCT options are introduced into the electric power development scenario after 1996. Installed capacity of power generation from CCTs totals 42.4 GW in 2011. The capacity shortfall under this scenario is estimated at 45.3 GW in 2011, which is 4.5 GW lower than that in the Reference Case.

Emissions of all forms, excepting nuclear waste, are down significantly from Reference Case levels over the projection period. Particulate emissions in 2011 are 2 percent lower compared to the Reference Case in 2011 due to the higher efficiency of IGCC units. SO_2 and NO_x emissions are 1.05 Mt and 0.78 Mt per annum less than Reference Case levels in 2011.

Table f. Clean coal technology scenario

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	55189	66853	96891	125954
Nuclear	1785	3214	6131	12051	18004
Natural Gas	2587	2485	20572	21100	21405
Hydro	19189	26966	35459	44080	56435
Subtotal	69070	87854	129016	174122	221798
% Hydro	27 8%	30 7%	27 5%	25 3%	25 4%
Capacity shortfall	0	0	8567	15961	45291
% of Gen subtotal	0	0	6.6%	9 2%	20 4%
Installed Generation (MW)					
Decentralized Power	0	444	3200	4800	6400
Clean Coal Technologies	0	1365	1668	12176	42413
Energy Resource Consumption					
Hydro (MW)	9344	13386	18523	23421	30587
Coal ('000 tonnes)	129282	169053	243493	320000	406000
Natural Gas (millions m3)	3322	3190	12836	14084	14700
Fuel Oil ('000 m3)	910	1203	1783	2206	2190
Nuclear Fuel ('000 kg U)	857	1398	3122	6203	9299
Environmental Emissions					
Particulates ('000 tonnes)	413697	435788	632 753	4833057	4854890
CO2 ('000 tonnes)	224793	291750	414 154	568955	715485
SO2 ('000 tonnes)	1230	1573	2 761	2856	2926
NOx ('000 tonnes)	1193	1524	1 777	2781	3005
Nuclear Waste ('000 m3)	9945	16228	9 087	72015	107967

Table g. Clean coal technology scenario minus reference scenario

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	241	-474	5389	532
Nuclear	0	0	0	0	0
Natural Gas	0	0	89	89	-622
Hydro	0	-202	197	-2780	-2980
Subtotal	0	38	-187	2698	-3069
Capacity Shortfall	0	0	1	-2344	-453
Total Capacity Required	0	38	-185	354	-3522
Installed Generation (MW)					
Decentralized Power	0	-55	0	0	0
Demand-side Management	0	0	0	0	0
Cogeneration	0	0	0	0	0
Clean Coal Technologies	0	1365	1668	12176	42413
Energy Resource Consumption					
Hydro (MW)	0	-121	118	-1666	-1786
Coal ('000 tonnes)	0	104	-2531	0	0
Natural Gas (millions m3)	0	0	278	368	0
Fuel Oil ('000 m3)	0	-32	-61	-273	-1034
Nuclear Fuel ('000 kg U)	0	11	0	0	0
Environmental Emissions					
Particulates ('000 tonnes)	0	-15024	-28554	-339974	99579
CO2 ('000 tonnes)	0	131	-3778	767	-359
SO2 ('000 tonnes)	0	-34	-64	-291	-1048
NOx ('000 tonnes)	0	-25	-53	-217	-775
Nuclear Waste ('000 m3)	0	124	0	0	0

Cogeneration scenario

Cogeneration results are displayed in Table h and Table i.

About 21 GW of additional capacity is available from cogeneration in 2011, thus reducing the shortfall in installed capacity requirement from 20 percent in the Reference case to 15 percent in the Cogeneration option.

Of the total cogeneration capacity that comes on stream, nearly 90 percent is bagasse based cogeneration in sugar mills. The remaining is waste heat recovery in other energy intensive industries. Bagasse-based cogeneration is neutral in terms of CO_2 emissions and can save about 1.24 kg of CO_2 per kWh of electricity. There is not much difference in the overall levels of emissions under the Cogeneration and Reference Cases, which should be expected as coal and natural gas consumption are the same under the two scenarios (i.e. upper bound of fuel available for power sector)

Table h. Cogeneration scenario

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	49941	62392	91425	122540
Nuclear	1785	3214	4831	10751	16704
Natural Gas	2587	2485	20651	21178	21636
Hydro	19189	26744	34737	43027	54182
Other	0	6615	9427	13799	20844
Subtotal	69070	88999	132039	180181	235906
% Hydro	27 8%	30 0%	26 3%	23.9%	23 0%
Capacity Shortfall	0	0	7323	13216	35303
% Gen Subtotal	0 0%	0 0%	5 5%	7.3%	15 0%
Total Capacity Required	69070	88999	139362	193398	271210
Installed Generation (MW)					
Decentralized Power	0	100	3200	4800	6400
Demand-side Management	0	0	0	0	0
Cogeneration	0	6615	9427	13799	20844
Clean Coal Technologies	0	0	0	0	0
Energy Resource Consumption					
Hydro (MW)	9344	13452	18107	22806	29254
Coal ('000 tonnes)	129282	172000	228564	320000	406000
Natural Gas (millions m3)	3322	3190	12646	13827	14443
Fuel Oil ('000 m3)	910	1239	1701	2480	3204
Nuclear Fuel ('000 kg U)	857	1602	2446	5527	8624
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4896904	5287901	5173227	5208129
CO2 ('000 tonnes)	224793	296677	411291	568430	715203
SO2 ('000 tonnes)	1230	1636	2270	3149	3973
NOx ('000 tonnes)	1193	1576	2164	2998	3778
Nuclear Waste ('000 m3)	9945	18603	28401	64169	100121

Table i. Cogeneration scenario minus reference case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	-5007	-4935	-76	-2881
Nuclear	0	0	-1300	-1300	-1300
Natural Gas	0	0	168	168	-391
Hydro	0	-424	-524	-3832	-5232
Other	0	6615	9427	13799	20844
Subtotal	0	1183	2835	8757	11038
Capacity Shortfall	0	0	-1242	-5089	-10441
Total Capacity Required	0	1183	1593	3668	597
Installed Generation (MW)					
Decentralized Power	0	-400	0	0	0
Demand-side Management	0	0	0	0	0
Cogeneration	0	6615	9427	13799	20844
Clean Coal Technologies	0	0	0	0	0
Energy Resource Consumption					
Hydro (MW)	0	-55	-298	-2281	-3119
Coal ('000 tonnes)	0	3051	-17460	0	0
Natural Gas (millions m3)	0	0	88	111	-257
Fuel Oil ('000 m3)	0	2	-143	1	-20
Nuclear Fuel ('000 kg U)	0	215	-676	-676	-675
Environmental Emissions					
Particulates ('000 tonnes)	0	523992	-81361	196	452818
CO2 ('000 tonnes)	0	5058	-29354	242	-641
SO2 ('000 tonnes)	0	28	-165	1	-1
NOx ('000 tonnes)	0	27	-157	0	-2
Nuclear Waste ('000 m3)	0	2499	-7846	-7846	-7846

Reduced losses

The high levels of T & D losses, averaging about 22 percent of total generation at the busbar, is an issue of major concern for the Indian power system Indeed, reducing these losses to more acceptable levels is estimated to be one of the most economic options for improving both system performance and reliability.

Table j and Table k summarizes the impact of reducing system T & D losses from 22 percent to 15 percent on an across-India basis. The installed capacity for this case is about 2 GW more than virtually the same as the Reference Case in 2011. The capacity shortfall is down significantly (18.75 GW) by 2011 compared to the Reference Case

The major reduction in emissions recorded in the 1991-2006 period (see Table) is reversed in the final reporting periods.

Table j. Reduced losses scenario

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	49364	67032	98392	127177
Nuclear	1785	3214	6131	12051	18004
Natural Gas	2587	2485	19789	19946	22619
Hydro	19189	29364	38017	47645	60000
Subtotal	69070	84428	130970	178035	227800
% Hydro	27 8%	34 8%	29 0%	26 8%	26 3%
Capacity Shortfall	0	0	0	3239	26999
% Gen Subtotal	0 0%	0 0%	0 0%	1 8%	11 9%
Total Capacity Required	69070	84428	130970	181274	254800
Installed Generation (MW)					
Decentralized Power	0	0	2200	4800	6400
Demand-side Management	0	0	0	0	0
Cogeneration	0	0	0	0	0
Clean Coal Technologies	0	0	0	0	0
Energy Resource Consumption					
Hydro (MW)	9344	14477	20056	25557	32723
Coal ('000 tonnes)	129282	149725	215444	310780	406000
Natural Gas (millions m3)	3322	3190	12193	12628	14700
Fuel Oil ('000 m3)	911	1079	1620	2419	3222
Nuclear Fuel ('000 kg U)	856	1456	3122	4636	9299
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4257350	4606628	4773921	4766722
CO2 ('000 tonnes)	224793	259107	388283	550503	715817
SO2 ('000 tonnes)	1230	1424	2141	3049	3975
NOx ('000 tonnes)	1193	1376	2043	2905	3780
Nuclear Waste ('000 m3)	9945	16906	36247	53829	107967

Table k. Reduced losses minus reference case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	-5583	-295	6890	1755
Nuclear	0	0	0	0	0
Natural Gas	0	0	-694	-1064	592
Hydro	0	2196	2756	785	585
Subtotal	0	-3387	1767	6611	2932
Capacity Shortfall	0	0	-8565	-15066	-18745
Total Capacity Required	0	-3387	-6798	-8455	-15812
Installed Generation (MW)					
Decentralized Power	0	-500	-1000	0	0
Demand-side Management	0	0	0	0	0
Cogeneration	0	0	0	0	0
Clean Coal Technologies	0	0	0	0	0
Energy Resource Consumption					
Hydro (MW)	0	970	1651	470	350
Coal ('000 tonnes)	0	-19224	-30580	-9220	0
Natural Gas (millions m3)	0	0	-365	-1088	0
Fuel Oil ('000 m3)	0	-157	-225	-60	-2
Nuclear Fuel ('000 kg U)	-0	69	0	-1567	0
Environmental Emissions					
Particulates ('000 tonnes)	0	-115562	-762634	-399110	11411
CO2 ('000 tonnes)	0	-32512	-52362	-17685	-27
SO2 ('000 tonnes)	0	-183	-293	-98	0
NOx ('000 tonnes)	0	-172	-278	-92	-0
Nuclear Waste ('000 m3)	0	802	0	-18186	0

Optimistic scenario

The preceding scenarios have analyzed the introduction of alternative technologies and system enhancements on an independent basis. Assuming that initiatives could be undertaken on all these options simultaneously, it is appropriate to assess a scenario that combines all the above planning options.

The Optimistic Case presents the best that is achievable, given the overriding constraints on financial investment, coal consumption, natural gas consumption, and hydroelectric capacity expansion contained in the Reference Case While it may be optimistic, it remains a more realistic scenario than that provided by the financially unconstrained Base Case

In many respects, this scenario represents the outcome of an IRP approach to electric power development, in which all supply-and demand-side options for meeting the demand for electricity services are compared on a least-cost basis This planning paradigm is finding increasing acceptance among North American electric and gas utilities as an efficient and cost-effective approach to development planning.

As shown in Table l and Table m, the optimistic scenario results in a significant improvement in system development relative to the Reference Case. The efficiencies available from DSM, reduced losses, Clean Coal Technologies and Cogeneration enable an additional 9 35 GW of installed generation capacity to be put in place by 2011, relative to the Reference Case. More important, there is no capacity shortfall until 2016. Total capacity requirements in 2011 reach 234 GW or 3.4 times the 1991 system capacity, *versus* 544 GW for the Reference Case (7.9 times 1991 levels).

Of the generation options made available to the model, 11.13 GW of DSM, 4.4 GW of renewable generation capacity, 13.3 GW of cogeneration, and 23.8 GW of CCT capacity are adopted.

Table I. Optimistic scenario–reference case with all options open

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	43716	59631	86217	133500
Nuclear	1785	2814	4831	10751	16704
Natural Gas	2587	4968	19889	20489	20866
Hydro	19189	23938	33334	42243	49854
Other	0	0	1900	6272	13294
Subtotal	69070	75436	119586	165974	234218
% Hydro	27 8%	31 7%	27 9%	25.5%	21 3%
Total Capacity Required	69070	75436	119586	165974	234218
Installed Generation (MW)					
Decentralized Power	0	500	1240	1500	4400
Demand-side Management	0	2557	4893	7076	11129
Cogeneration	0	0	1900	6272	13294
Clean Coal Technologies	0	0	0	6439	23777
Energy Resource Consumption					
Hydro (MW)	9344	11963	17280	22350	26674
Coal ('000 tonnes)	129282	146055	208756	282385	406000
Natural Gas (millions m3)	3322	4496	12245	12473	12623
Fuel Oil ('000 m3)	911	1030	1547	2040	2702
Nuclear Fuel ('000 kg U)	856	1394	2446	5527	8624
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4673456	4931076	4639175	4704719
CO2 ('000 tonnes)	224793	255448	377018	501976	711528
SO_2 ('000 tonnes)	1230	1402	2077	2634	3421
NO_x ('000 tonnes)	1193	1353	1983	2539	3364
Nuclear Waste ('000 m3)	9945	16189	28401	64169	100121

Table m. Optimistic scenario minus reference case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	-11232	-7696	-5284	8079
Nuclear	0	-400	-1300	-1300	-1300
Natural Gas	0	2483	-594	-520	-1161
Hydro	0	-3230	-1926	-4616	-9561
Other	0	0	1900	6272	13294
Subtotal	0	-12378	-9616	-5449	9350
Capacity Shortfall	0	0	-8565	-18305	-45745
Total Capacity Required	0	-12378	-18182	-23755	-36394
Installed Generation (MW)					
Decentralized Power	0	0	-1960	-3300	-2000
Demand-side Management	0	2557	4893	7076	11129
Cogeneration	0	0	1900	6272	13294
Clean Coal Technologies	0	0	0	6439	23777
Energy Resource Consumption					
Hydro (MW)	0	-1544	-1125	-2737	-5699
Coal ('000 tonnes)	0	-22894	-37268	-37615	0
Natural Gas (millions m3)	0	1306	-313	-1243	-2077
Fuel Oil ('000 m3)	0	-206	-297	-438	-521
Nuclear Fuel ('000 kg U)	-0	7	-676	-676	-675
Environmental Emissions					
Particulates ('000 tonnes)	0	300544	-438186	-533856	-50592
CO2 ('000 tonnes)	0	-36171	-63627	-66212	-4316
SO2 ('000 tonnes)	0	-205	-357	-513	-553
NOx ('000 tonnes)	0	-195	-338	-458	-417
Nuclear Waste ('000 m3)	0	85	-7846	-7846	-7846

Business-as-usual with all options plus gas import

Building on the optimistic scenario discussed above, this scenario assumes that an integrated planning approach to electric power development is put in place, that there are no financial constraints on India's electric power development, and that India is able to import gas from the Middle East to an upper limit of 30 million cubic meters per year.

As shown in Table n and Table o, this scenario results in a significant improvement in system development relative to the Base Case. The efficiencies available from DSM, reduced losses, clean coal technologies, and cogeneration, coupled with relaxing the financial constraint on system development, compound to yield a decrease of 47 GW in installed generation capacity in 2011 compared to the Base Case More important, there is no capacity shortfall in this case

Natural gas capacity increases almost 23 5 times its 1991 level by 2011 under this scenario. The relaxation of the coal and financial constraints results in an increase in coal-based installed capacity, from 125 GW in 2011 in the Reference Case to 130 GW under this option. The share of hydro-electric capacity is placed at 18.3 percent While DSM is seen to reach potential of 11.13 GW, renewables capacity is only 2 GW and cogeneration 1.45 GW.

The impact on levels of emission is significant. All emissions are lower compared to the Base Case. Particulate emissions are reduced by 1,598 Mt, CO_2 by 461 Mt, SO_2 by 2.7 Mt, and NO_x by 2.6 Mt in 2011 under this scenario relative to the Base Case.

Table n. BAU with all options plus gas import

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	45509	43716	61084	86404	130067
Nuclear	1785	2814	4831	4751	4704
Natural Gas	2587	4968	20438	36781	60603
Hydro	19189	23938	32952	39146	44210
Other	0	0	312	793	1449
Subtotal	69070	75436	119617	167876	241034
% Hydro	27 8%	31 7%	27 5%	23.3%	18 3%
Total Capacity Required	69070	75436	119617	167876	241034
Installed Generation (MW)					
Decentralized Power	0	500	1120	1500	2000
Demand-side Management	0	2557	4893	7250	11129
Cogeneration	0	0	312	793	1449
Energy Resource Consumption					
Hydro (MW)	9344	11963	17051	20495	23293
Coal ('000 tonnes)	129282	146055	208732	299496	448308
Natural Gas (millions m3)	3322	4496	12534	21036	33508
Fuel Oil ('000 m3)	911	1030	1555	2304	3532
Nuclear Fuel ('000 kg U)	856	1394	2446	2407	2385
Environmental Emissions					
Particulates ('000 tonnes)	4136978	4673456	4788019	5133851	5720476
CO2 ('000 tonnes)	224793	255448	377593	548118	824770
Nuclear Waste ('000 m3)	9945	16189	28401	27955	27693

Table o. BAU plus all options minus base case

Year	1991	1996	2001	2006	2011
Installed Generation (MW)					
Coal	0	-2762	-20684	-47221	-84174
Nuclear	0	0	0	0	0
Natural Gas	0	-8222	83	15745	38353
Hydro	0	-2471	-2875	-2030	-2875
Other	0	0	312	793	1449
Subtotal	0	-13456	-23164	-32713	-47247
Capacity Shortfall	0	0	0	0	0
Total Capacity Required	0	-13456	-23164	-32713	-47247
Installed Generation (MW)					
Decentralized Power	0	0	-2080	-3300	-4400
Demand-side Management	0	2557	4893	7250	11129
Cogeneration	0	0	312	793	1449
Clean Coal Technologies	0	0	0	0	0
Energy Resource Consumption					
Hydro (MW)	0	-1489	-1723	-651	1116
Coal ('000 tonnes)	0	-16847	-47519	-95755	-174099
Natural Gas (millions m3)	0	-4322	44	8275	20158
Fuel Oil ('000 m3)	0	-130	-407	-819	-1459
Nuclear Fuel ('000 kg U)	0	0	152	481	760
Environmental Emissions					
Particulates ('000 tonnes)	0	-270103	116780	286730	-122735
CO2 ('000 tonnes)	0	-37103	-80337	-145527	-254210
SO2 ('000 tonnes)	0	-203	-451	-827	-1453
NOx ('000 tonnes)	0	-187	-427	-794	-1401
Nuclear Waste ('000 m3)	0	0	1771	5592	8825

Scenario comparisons

With the notable exception of the Optimistic scenario, there is not a clear winner among the development scenarios discussed above. From a policy and planning standpoint, the choice of priorities among the various options will, therefore, depend on the decision criteria used for assessment. This section provides a comparison of scenario results on the basis of three candidate criterion:

- capacity shortfall,
- SO_2, No_x, and CO_2 emissions; and
- total electric power system costs.

Capacity shortfall

If satisfying demand is an overriding priority in system development, then one important criterion for selection among the various alternative scenarios could be to minimize capacity shortfall Table p provide a comparison of capacity shortfalls under the reference and alternative scenarios. All the alternative scenarios result in a reduced capacity shortfall relative to the Reference Case. Under the DSM, Reduced T & D Losses, and Optimistic

scenarios, capacity shortfalls are eliminated until the 2006 reporting period. That is, all projected demand for electricity services are met under these scenarios. While capacity shortfalls appear thereafter, under the Reference plus All Options scenario, the shortfall is eliminated until the year 2011.

All scenarios with an investment constraint result in capacity shortfalls ranging from 27-70 percent. While each individual option such as DSM, Cogeneration, etc. indicate shortfalls around 50-60 percent, the combination scenario with investment constraints indicates a substantially reduced shortfall of 27 percent When the investment constraints are reduced, shortfalls are eliminated Assuming that funds estimated under the constrained scenario would indeed be made available by the government, the obvious conclusion would be that the additional funds would have to be raised from the private sector, both domestic and foreign, in order to eliminate shortfalls and satisfy all the demand.

Table p. Scenario comparisons - required system capacity ('000 MW)

Year	1996	2001	2006	2011
Base Case	98 8	169 4	238 4	347 9
Reference Case	101 3	165 3	231 2	323 2
DSM Scenario	98 7	155 7	216 0	300 2
(% Reference Case)	(97 4)	(94 2)	(93 4)	(92 9)
Clean Coal Technology Scenario	101 3	165 3	231 2	320 5
(% Reference Case)	(100 0)	(100 0)	(100 0)	(99 2)
Cogeneration Scenario	95 4	150 9	204 5	279 2
(% Reference Case)	(94 2)	(91 3)	(88 5)	(86 4)
Reduced T&D Losses Scenario	98 1	158 6	220 8	309 6
(% Reference Case)	(96 8)	(95 9)	(95 5)	(95 8)
Reduced Reserve Margin Scenario	97 5	147 6	205 5	298.0
(% Reference Case)	(96 2)	(89 3)	(88 9)	(92.2)
Optimistic Scenario	88 2	123 8	162 0	215.6
(% Reference Case)	(87 1)	(74 9)	(70 1)	(66 7)

Emissions

Limiting CO_2 emissions has gained importance since their identified link to the threat of global warming. While presently, India does not have any commitments for CO_2 and other GHG emissions reductions, the need to study the emissions from different scenarios gains relevance, considering the three-fold growth of the Indian power sector by 2011 identified in the Reference Case.

Table q compares CO_2 emissions under the eight scenarios examined, for the reporting periods 1996 through 2011. Under the unconstrained Base Case, CO_2 emissions from the electric power sector exceed 1078 Mt per year by 2011, 3.7 times their estimated 1996 level. Under the Reference Case, CO_2, emissions are estimated at 715 Mt in 2011, that is roughly 66 percent of Base Case levels. This is largely due to the considerable unsatisfied

electricity demand represented by the capacity shortfall of 45.75 GW in that year, the majority of which is avoided coal-fired generation relative to the Base Case

The DSM, Reduced T & D Losses, and Optimistic scenarios all yield comparable emissions results, since the level of coal available for power generation is constrained to 650 Mt in all the scenarios. However, the level of capacity shortfall relative to the Reference Case is lower in all these options. The Optimistic scenario, with its comparatively lower CO_2 emissions (see Table q) coupled with a 27 percent capacity shortfall, makes this a preferred option.

As SO_2, NO_X and particulates are of greater short-term interest to power planners in India than greenhouse gas concerns, Table r though present these emissions for the eight different scenarios examined. Clean Coal scenario is clearly preferable if SO_2, NO_X and particulate emissions are of primary interest, followed by the Optimistic scenario.

Table q. Scenario comparisons - capacity shortfall (MW)

Year	1996	2001	2006	2011
Reference Case	0	4 242	9 151	49 640
DSM Scenario	0	0	0	22 874
(% Reference Case)	0	0	0	(46 1)
Clean Coal Technology Scenario	0	4 242	9 151	51 023
(% Reference Case)	0	(100 0)	(100 0)	(102 8)
Cogeneration Scenario	0	2991	6 625	44 931
(% Reference Case)	0	(70 5)	(72 4)	(90 5)
Reduced T&D Losses Scenario	0	0	0	32 539
(% Reference Case)	0	0	0	(65 5)
Reduced Reserve Margin Scenario	0	0	0	29 519
(% Reference Case)	0	0	0	(59 5)
Optimistic Scenario	0	0	0	0
(% Reference Case)	0	0	0	0

Table r. Scenario comparisons - carbon dioxide emissions (Mt)

Year	1991	1996	2001	2006	2011
Base Case	182 1	245 6	404 8	614 1	956 9
Reference Case	182 1	259 6	414 2	623 4	687 4
DSM Scenario	182 1	228 0	335 2	504 8	683 7
(% Reference Case)	(100 0)	(87 8)	(80 9)	(80 9)	(99 5)
Clean Coal Technology Scenario	182 1	259 6	414 2	623 4	681 1
(% Reference Case)	(100 0)	(100 0)	(100 0)	(100 0)	(99 1)
Cogeneration Scenario	182 1	260 6	461 2	679 1	1 088 0
(% Reference Case)	(100 0)	(100 4)	(111 3)	(109 0)	(158 4)
Reduced T&D Losses Scenario	166 8	232 5	374 0	567 4	690 9
(% Reference Case)	(91 6)	(89 6)	(90 3)	(91 0)	(100 6)
Reduced Reserve Margin Scenario	182 1	244 6	395 3	588 3	679 1
(% Reference Case)	(100 0)	(94 2)	(95 4)	(94 4)	(98 9)
Optimistic Scenario	182 1	232 3	369 8	593 5	959 7
(% Reference Case)	(100 0)	(89 5)	(89 3)	(95 2)	(139 7)

Total system costs

The total system cost is defined as the cost of total power system development as well as the cost of unsatisfied demand The ELITE model minimizes the total system cost for meeting a specified level of demand (totally or in part) under the given set of constraints. While each scenario introduces a different option into the final solution, it is the integration of these choices available that requires greater attention. The attempt here would be to study all the preferred choices to be evaluated in an integrated framework.

As shown in the final two scenarios discussed above, imposing a financial constraint on electric power development and coupling this with recourse to all options in an integrated planning context offers many benefits. Relative to the other scenarios examined here, it offers the best attributes available, if we are concerned with reducing emissions and reducing unsatisfied demand for electricity. As shown in Table , using all options to satisfy power demand also allows the lowest total installed system cost, whether a financial constraint is imposed or not

As shown in Table, the total costs to build and operate the electric power system represented in the BAU Plus all Options Case is 82.5 percent of the unconstrained BAU Case. That is, making good use of DSM, cogeneration, reducing distribution losses, etc., actually results in an 18 percent decrease in total system costs--a significant financial savings of Rs 80,031 crores. In the scenario where realistic financial constraints are imposed on power development, the total system cost is only 86 percent of the unconstrained BAU Plus All Options levels. Whether or nor financial constraints are imposed is, therefore, not a central issue--these results indicate that there are large cost and emissions savings that would result from institution of IRP for Indian electric power development.

Policy implications for Indian power sector development

The preferred development strategy is clearly the adoption of IRP and joint implementation of all development option This is the outcome represented in the Optimistic scenario. Pursuing this development strategy will require considerable change in the structure, operations, regulation, and decision making practices currently governing electric power development in India. Specific policy initiatives required in each of the planning options are discussed below.

Demand-side management

The main impact of the DSM option is on reducing the capacity shortfall and thus postponement of new capacity additions The success of DSM programs and actual efficiency gains depends on the concerted efforts of the government utilities, manufactures, and electricity consumers themselves, in overcoming the barriers that limit successful

implementation of energy efficiency and DSM. The governments have an important catalyti role in promoting energy efficiency through various economic and financial instruments and should formulate policies that would encourage greater end-use efficiency Possible strategies that would be considered in promoting energy efficiency are.

- develop a national program on energy efficiency;
- SEBs should be encouraged to develop comprehensive DSM plans,
- introduce the concept of IRP;
- design and adopt energy conservation laws and regulations, and
- set efficiency standards for energy consuming equipment

Perhaps the most important barrier in promoting energy efficiency is the present electricity pricing policies of the SEBs, where electricity is supplied at a rate much lower tha the marginal cost of its generation and supply. In fact, for several consumer categories, such as agriculture, domestic, and small industries, tariffs are lower than the average cost of generation and supply. Such tariffs do not provide the right signals to consumers in influencing their consumption behavior. Nor do they generate adequate revenue to maintain the reliability and integrity of the existing power system The utilities, thus, need to rationalize their tariff policies and also consider various innovative tariff options such as time-of-use tariffs, interruptible rates, etc , to manage the demand for electricity.

Information dissemination is the key to the success of energy efficiency and DSM programs While there are ongoing efforts ongoing by several organizations, there is a need to consolidate these efforts in order to ensure that there is maximum outreach. Information dissemination can be achieved through mass media-based awareness campaigns on energy conservation, energy labelling, training of various consumer groups, and developing databases on energy use and efficiency improvements for easy access to the consumers.

The Ministry of Power and the EMC are the nodal organizations responsible for energy efficiency activities in the country. DSM, as a subset of energy efficiency, should be given a major thrust by initiating demonstration projects in selected utilities in the country. Strong networking, preparation of a national program on energy efficiency and DSM with specific targets, and provision of effective support by way of suitable fiscal and financial incentives and/or penalties, are immediately required if the country is to gain from the benefits of energy efficiency.

Clean coal technologies

In view of the fact that the Indian power sector will continue to rely heavily on coal-based generation, and the growing concerns towards global warming, India needs to consider various CCT options for coal-based power generation. The technologies should be evaluate

both in terms of efficiency and cost considerations, and a long term strategy should be developed for the introduction of these technologies into the Indian market.

Among the various CCTs, IGCC, PFBC and AFBC offer potential for adoption in India in the future, owing to their cost effectiveness, availability, and potential for meeting emission control requirements The R&D efforts in developing these technologies should be strengthened and demonstration projects should be initiated to evaluate viability and the potential for commercialization of these technologies A reasonable target would be to introduce CCTs into the Indian Power System by the year 2000.

Another important aspect that needs attention is washing of non-coking coal for power generation. The economic advantages of coal washing in the Indian context are well documented. Washing costs are estimated to be in the range of Rs 100-150 per tonne, which is more than offset by transportation cost savings, even if no credit is taken for availability improvements in the power plant Coal washing is economically justified whenever transportation distances are greater than about 1000 km.

Cogeneration

Cogeneration potential in energy intensive industries in India such as sugar, textiles, paper, fertilizers, food processing, chemicals and petrochemical is significant. Sugar industries alone offer a cogeneration potential of about 5100 MW out of a total estimated cogeneration potential of 7574 MW in 1993

Cogeneration of electricity and steam in energy intensive industries offers increased system and fuel efficiency to the industries. It reduces the industries demand for utility power and carries the potential for surplus generation which could be sold to the utilities. Cogeneration thus provides an alternative to conventional utility power and reduces the overall emissions from the power sector. Bagasse-based cogeneration, in particular, being neutral in terms of CO_2 emissions, offers significant environmental benefits.

The potential market for cogeneration in Indian industry will be influenced by energy prices, the economic situation, restructuring tariff regimes, power wheeling and banking facilities, and availability of technology and finances. It is important to have long term purchase contracts between the SEBs and cogenerators for purchase of surplus power to encourage industries to opt for cogeneration A regulatory framework, such as PURPA (Public Utility Regulatory Policy Act) in which it is mandatory for the public utilities to buy the energy generated by the cogenerator at avoided cost in the U.S. should be examined for possible application to India.

Transmission and distribution loss reduction

The impact of the excessive T & D losses in the Indian power system is two-fold. First, it results in under-utilization of the total energy that is being generated. Second, the energy lost due to excessive T & D losses is required to be compensated for by setting up new generating stations which impose increased financial burden and environmental concern from power generation.

Adequate resources must be provided by the SEBs for strengthening their T & D system and reducing losses Reduction in technical losses requires transmitting at higher voltages and appropriate HV/LV ratio of transmission lines Sub-transmission and distribution systems operated by the SEBs are over-stressed due to resource constraints. The distribution systems in the past have been extended from time to time to cater to the immediate load demand rather than on the basis of systematic planning This has resulted in poor quality of supply, high T & D losses, frequent transformer burnouts etc . There is thus, an urgent need to strengthen the electricity distribution system by stepping up investment in this sector. The power utilities must formulate comprehensive schemes for development and improvement of sub-transmission and distribution systems by adopting a systematic and methodical approach to planning and design of the distribution system.

In the lower voltage networks, in addition to the augmentation of the network, installation of capacitors, re-conductoring, and eliminating underloading and overloading of distribution transformers, are all required in order to reduce losses SEBs must undertake system improvement schemes with the objective to reduce T & D losses and to provide electricity to a greater number of the population with increased reliability and quality.

Curtailment of non-technical losses, which presently accounts for one-third of the total T & D losses, requires a judicious mix of legislative support, increased customer awareness, improved billing and collection procedures, and reliable and high quality meters.

Private sector participation in Indian power sector

With the resources constraints of the central and state governments, it will be impossible for the government to provide all the resources required for power sector development in future. All the planning options discussed above offer large scope for private sector participation. The GOI has, since 1991, opened the doors to the private sector for participation in power generation but there are several issues that yet remain to be resolved It is important for the central and the state governments to take appropriate measures to resolve these issues to encourage private sector participation

Apart from investing in conventional power generation facilities, the private sector has large investment opportunities in India in renewable energy projects such as wind, biomass-based gasifiers, and cogeneration.

The private sector could be involved in the area of DSM--private investors can participate through manufacturing of energy efficient equipment, as well as setting up energy service companies to offer technical and financial assistance in promoting energy efficiency.

State electricity boards

The successful adoption of various supply and demand-side planning options for the growth and development of the power sector hinges on the performance and financial viability of the SEBs. The boards must be insulated from interference by the state governments in day-to-day matters and the role of state governments restricted to only advisory, as envisaged in the Electricity (Supply) Act SEBs must be entrusted with greater autonomy and accountability in their operations In particular, tariff reform is an area where there is an urgent need to eliminate state government influence and introduce cost-based pricing principles. An autonomous tariff commission/board needs to be set up which would determine electricity prices in a rational and transparent manner. An independent regulatory body is essential for the efficient development of the power sector in the future.

This study has examined a number of options available to the Indian power sector in meeting the country's rapidly growing demand for electricity. Continuation of current practices suggests a future of growing surplus electricity demand and declining electricity system reliability.

There is however, much that can be done to ameliorate these problems, even in the context of financial and energy resource constraints facing the country Adoption and implementation of integrated resource planning in the power sector, movement toward cost-based pricing principles, and creation (and empowerment) of an independent regulatory authority to oversee the future expansion and operation of the power system